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LATHAM & WATKINS LLP

January 25, 2011

File No. 039610-0003

DOCKET
08-AFC-9
DATE JAN 25 2011
RECD. JAN 25 2011

VIA FEDEX

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 08-AFC-9
1516 Ninth Street, MS-4
Sacramento, California 95814-5512

Re: City of Palmdale Hybrid Power Plant Project: Docket No. 08-AFC-9

Dear Sir/Madam:

Pursuant to California Code of Regulations, title 20, Sections 1209, 1209.5, and 1210, enclosed herewith for filing please find Applicant's letter to U.S. EPA regarding Supplemental Information for the Application for PSD Permit, dated July 21, 2010 (with enclosure).

Please note that the enclosed submittal was filed today via electronic mail to your attention and to all parties on the attached proof of service list.

Very truly yours,

Paul E. Kihm
Senior Paralegal

Enclosure

cc: 08-AFC-9 Proof of Service List (w/encl., via e-mail and U.S. Mail)
Michael J. Carroll, Esq. (w/encl.)
Marc T. Campopiano, Esq. (w/encl.)

OC\1135312.1

AECOM

AECOM Environment
1220 Avenida Acaso
Camarillo, CA 93012

(805)388-3775 tel
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July 21, 2010

Mr. Gerardo Rios
Chief, Permits Office (AIR 3)
U.S. Environmental Protection Agency
75 Hawthorne Street
San Francisco, CA 94105

RE: Palmdale Hybrid Power Project (PHPP) – Supplemental Information for the Application for PSD Permit

Dear Mr. Rios:

AECOM Environment, on behalf of the City of Palmdale and Inland Energy, Inc., is submitting the enclosed Supplemental Information on the application for a Prevention of Significant Deterioration (PSD) permit for the Palmdale Hybrid Power Project (PHPP). The PHPP is a hybrid power plant consisting of combined-cycle power plant integrated with 50 megawatts (MW) of solar arrays for a combined nominal output of 570 MW. The PSD application for PHPP was submitted to EPA on April 1, 2009. This supplemental information is being provided in response to a conference call held between EPA Region 9 staff, Inland Energy, Latham & Watkins, and AECOM on March 14, 2010. EPA indicated that the PHPP PSD Application would be complete if the following items were addressed:

1. An expanded cumulative fine particulate matter (PM2.5) impact analysis to demonstrate compliance with the National Ambient Air Quality Standard (NAAQS). The EPA also requested additional analysis regarding the potential applicability of PM2.5 increment thresholds proposed in the Federal Register on September 21, 2007;
2. A 1-hour Nitrogen Dioxide (NO_2) NAAQS modeling analysis;
3. An expanded Soils and Vegetation analysis based on the Environmental Appeals Board case *In re: Indeck-Elwood, LLC*; PSD Appeal No. 03-04; PSD Permit No. 197035AAJ (decided September 27, 2006);
4. A Visibility analysis at local sensitive state or federal Class II areas;
5. Additional justification/documentation that the receptor grids used in the PSD modeling analysis out to 20 kilometers (km) are sufficient to identify the maximum impacts; and
6. A more detailed growth analysis than was submitted with the PSD application.

In addition to the above items, the EPA requested the following item, that was not a "completeness" item, but which would expedite the issuance of the permit:

7. Additional detail regarding the Best Available Control Technology (BACT) analysis

Enclosed please find three copies of the PSD Application Supplement. Since these supplemental materials do not change our Class I area analyses, we have not provided a copy to the National Park Service or the U.S. Forest Service.

We request that EPA review the supplemental information in a timely manner and move forward with processing the PSD permit application. Please let me know (by phone 805-388-3775 or email sara.head@aecom.com) if you or your staff have questions or need further supplemental information.

Sincerely

Sara J. Head, QEP
Vice President, AECOM Environment
Sara.head@aecom.com

Attachments: PSD Application Supplemental Information (3 copies)
DVD with modeling files (3 copies)

cc: Ms. Shirley Rivera, EPA
Ms. Felicia Miller, California Energy Commission (with 1 copy of the attachments)
Mr. Alan De Salvio, Antelope Valley Air Quality Management District
Ms. Laurie Lile, Assistant City Manager, Palmdale
Mr. Tom Barnett, Inland Energy, Inc.
Mr. Tony Penna, Inland Energy, Inc.
Mr. Mike Carroll, Latham & Watkins

Environment

Prepared for:
City of Palmdale &
Inland Energy

Prepared by:
AECOM
Camarillo, CA
60138827
June 2010

Palmdale Hybrid Power Project

PSD Application, Supplemental Information

AECOM Environment

Prepared for:
City of Palmdale &
Inland Energy

Prepared by:
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June 2010

Palmdale Hybrid Power Project

PSD Application, Supplemental Information

Prepared By Russell Kingsley

Reviewed By Sara J. Head

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1.0 Introduction

On April 1, 2009, an application for a Prevention of Significant Deterioration (PSD) permit was submitted to U.S. Environmental Protection Agency (EPA) Region 9 for the Palmdale Hybrid Power Project (PHPP). During a conference call on March 14, 2010, EPA identified a number of additional analyses that were indicated as necessary to deem the PSD application complete, as well as other items that were requested. The additional analyses that EPA requested are as follows:

1. An expanded cumulative fine particulate matter (PM2.5) impact analysis to demonstrate compliance with the National Ambient Air Quality Standard (NAAQS). The EPA also requested additional analysis regarding the potential applicability of PM2.5 increment thresholds proposed in the Federal Register on September 21, 2007;

2. A 1-hour Nitrogen Dioxide (NO_2) NAAQS modeling analysis;

3. An expanded Soils and Vegetation analysis based on the Environmental Appeals Board case *In re: Indeck-Elwood, LLC*; PSD Appeal No. 03-04; PSD Permit No. 197035AAJ (decided September 27, 2006);

4. A Visibility analysis at local sensitive state or federal Class II areas;

5. Additional justification/documentation that the receptor grids used in the PSD modeling analysis out to 20 kilometers (km) are sufficient to identify the maximum impacts; and

6. A more detailed growth analysis than was submitted with the PSD application.

In addition to the above items, the EPA requested the following items that were not “completeness” items, but which would expedite the issuance of the permit:

7. Additional detail regarding the Best Available Control Technology (BACT) analysis that evaluates all potential control technologies using a top-down approach to address each of the following specific source/control combinations:

    a. Electrostatic Precipitator (ESP), baghouses, and cyclones on gas turbines,

    b. Selective Catalytic Reduction (SCR) on fire water pumps or other internal combustion engines,

    c. A range of control options for the Project boilers, and

    d. Reconsideration of the emission limit for carbon monoxide (CO) emissions, with and without duct burners.

8. Provide any lists that the Applicant has developed for notifications, including any Indian tribes.

All of the above items except for item 8 are addressed in this Supplemental filing. The Applicant does not have additional mailing lists, and it is recommended that EPA obtain any updates for mailing lists from the California Energy Commission.

1.1 Project Overview

The PHPP is designed to use solar technology to generate a portion of the project's output and thereby support the State of California's goal of increasing the percentage of renewable energy supplies. Primary equipment for the generating facility will include two General Electric (GE) Frame 7FA natural gas-fired combustion turbine-generators (CTGs) rated at 154 megawatt (MW) each, two heat recovery steam generators (HRSGs) each rated at 169 MW, one steam turbine generator (STG) rated at 267 MW, and 251 acres of parabolic solar-thermal collectors with associated heat-transfer equipment. The 251-acre solar field would consist of parabolic solar-thermal collectors and associated heat transfer equipment arranged in rows. The proposed PHPP will have a nominal electrical output of 570 MW.

PHPP is designed for base load and peaking operations, with capability for rapid startup, shut-down, and load regulations, and to provide ancillary services. Compared to most other combined-cycle power plants, PHPP will be able to start-up in about half the time of other similar technologies as a result of GE's Rapid Start Process. Annual availability of the PHPP is expected to be in the range of 90 to 95 percent. During daylight periods when the solar collectors are in use, the solar field will provide heat directly to the HRSGs to produce steam, allowing the facility to reduce use of natural gas, and contributing up to 50 MW of generation from the STG.

Air emissions from the combustion of natural gas in the CTGs and duct burners of the HRSGs would be controlled using BACT. Oxides of nitrogen (NOx) emissions from the CTGs would be controlled by dry low-NOx combustors followed by a selective catalytic reduction (SCR) system in the HRSGs. An oxidation catalyst located within each HRSG would control CO and volatile organic compounds (VOC) emissions.

As indicated in the PSD Application submitted in April 2009, PHPP is projected to be a major source (i.e., have a potential to emit greater than 100 tons per year [tpy]) of NOx, VOC, CO, and total, respirable and fine particulate matter (PM/PM10/PM2.5). The Project will be a minor source of sulfur dioxide (SO_2), lead and other PSD-regulated pollutants, and hence these minor pollutants are not addressed further in this Supplement.

1.2 Project Application History

Besides the PSD Application submitted to the EPA in April 2009, applications were submitted to the California Energy Commission (CEC) and Antelope Valley Air Quality Management District (AVAQMD) in July 2008. The AVAQMD issued a Preliminary Determination of Compliance (PDOC) in February 2009, a Revised PDOC in June 2009, and a Final DOC in May 2010. A Preliminary Staff Assessment (PSA) was issued by the CEC in two parts, the first in December 2009 and the part that addressed air quality in February 2010.

1.3 Application Contacts

The following persons can be contracted for information regarding this application:

Steve Williams, City Manager, City of Palmdale
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805-388-3775
sara.head@aecom.com

1.4 Responsible Official Certification

Based on information and belief formed after reasonable inquiry, the statements and information contained in this supplement to the PSD application are true, accurate, and complete.

Signature: ____________________

Name: Steve Williams

Title: City Manager

2.0 PM2.5 Modeling Analyses

As noted in Section 1, EPA requested two analyses with respect to PM2.5 that are addressed in this section:

- A more extensive PM2.5 cumulative NAAQS analysis; and
- An analysis regarding the potential applicability of PM2.5 increment thresholds proposed in the Federal Register on September 21, 2007.

2.1 PM2.5 Cumulative Modeling Analysis

As part of their review of the PHPP PSD application submitted on April 1, 2009, EPA requested that the cumulative PM2.5 modeling analysis to determine compliance with the PM2.5 NAAQS that was included in the PSD Application be extended to include additional facilities. The details of that analysis are contained in this section, including the following information:

- Facilities included in the modeling;
- Sources included for each of the chosen facilities;
- Modeling methodology and analysis; and
- Discussion of results.

As shown in the modeling results, PHPP impacts, when modeled cumulatively with nearby major sources and with appropriate ambient background values added, show compliance with all applicable NAAQS and California Ambient Air Quality Standards (CAAQS) for PM2.5.

2.1.1 History and Choice of Facilities to be Included in PM2.5 Cumulative Analysis

The PHPP PSD Application submitted on April 1, 2009 contained a cumulative PM2.5 analysis which included other nearby (i.e., U.S. Air Force [USAF] Plant 42) sources of PM2.5 emissions. The USAF Plant 42 sources were the only ones that the AVAQMD had recommended be included for the cumulative modeling analysis for PM10/PM2.5. However, EPA requested that this cumulative analysis be expanded to include additional sources up to 50 km from the PM10 Significant Impact Area (SIA) from the power plant site. Since modeling had determined that the PM10 24-hour impacts fell to less than the Significant Impact Level (SIL) within 400 meters of the PHPP, an area of 51 km was used to assess the cumulative PM2.5 impacts.

For the purpose of this analysis, the sources considered (beside the ones in the immediate vicinity of the PHPP that were previously included) were major sources (i.e., >80 tpy of actual PM emissions) that were expected to have a sufficient emissions gradient to contribute cumulatively to the modeled PHPP impacts. Therefore, an inventory of PM emission sources with emissions greater than 80 tpy was requested from the AVAQMD on March 25, 2010. Mr. Chris Anderson, permit engineer with the AVAQMD, forwarded the request to the Mojave Desert Air Quality Management District (MDAQMD), Kern County Air Pollution Control District (KCAPCD) and South Coast Air Quality Management District (SCAQMD). Richard Wales of MDAQMD and Glen Stephens of KCAPCD responded quickly for their respective agencies that there were no facilities with annual PM emissions of more than 80 tpy within 51 km of PHPP in their district. After submitting additional information and follow-up requests over the following months, Lisa Ramos of SCAQMD indicated that there were not any sources meeting these criteria within the SCAQMD as well.

Chris Anderson initially identified two additional (beside the USAF Plant 42 sources previously included) facilities in the AVAQMD as candidates for inclusion in the modeling analysis, Granite Construction Company and Service Rock Products, now known as Robertson's Ready Mix. Although Granite Construction Company's emissions have dropped to less than 80 tpy, this source was still included in the revised PM2.5 modeling to be conservative. Additionally, because they were included in the prior PSD Application (March 2009), and because of their close proximity to the project site, Lockheed Martin Aeronautics and Northrop Grumman were also included in the cumulative modeling, despite their relatively low PM2.5 emissions (less than 10 tons per year each). The locations of these four facilities relative to the PHPP site are shown in **Figure 2-1**.

2.1.2 Characterization of Modeled Non-PHPP Sources

Once the four facilities to be included in the modeling analysis were chosen, the next step was to characterize the individual sources to be included in the modeling. The modeling of Lockheed Martin Aeronautics and Northrop Grumman had been previously discussed in Section 6.1.3 of the PHPP PSD Application. AVAQMD provided HARP model transaction files for all four facilities. In the transaction files for Granite Rock Construction and Robertson's Ready Mix, source coordinates and parameters were not available, while for Lockheed and Northrop, there were many sources with minimal emissions. In order to resolve these issues and other problems with the source data for these four facilities, the following adjustments were made:

- ***Lockheed Martin Aeronautics and Northrop Grumman:*** Because of the large number of sources at each facility, the vast majority of which had very low emissions, it was agreed with the AVAQMD, as described in Section 5.2.4.3 of the PHPP Application for Certification (AFC), to model all of the sources that included five percent or more of the emissions for each given pollutant, and then add the remainder of the total emissions to the source that emitted the highest percentage of the emissions in order to have a representative mix of source parameters, and to ensure that all criteria pollutant emissions from the two facilities were included in the modeling. **Figure 2-2** shows the locations of the two facilities and the sources that were included in the cumulative modeling. The characteristics and emissions for the Lockheed Martin Aeronautics and Northrop Grumman sources included in the cumulative modeling analysis are shown in **Tables 2-1** and **2-2**.

- ***Granite Rock Construction:*** As stated above, source parameters were not available for the emission sources located at Granite Rock Construction. The sources located at the facility are primarily crushing and mining of aggregate and sand, along with conveyors and other fugitive sources. This facility is located over nine miles from the PHPP. As a result, it was decided to represent the emissions from the facility as a single area source with the same characteristics as the fugitive emission sources used to represent construction activities at PHPP. The emissions for the facility were represented by a single area source 54,000 square meters (m^2) in area centered on the part of the facility where the majority of the emissions occur. The source characteristics and emissions for Granite Rock Construction are shown in **Table 2-3**.

- ***Robertson's Ready Mix:*** As with Granite Rock Construction, source parameters were not available for the emission sources located at Robertson's Ready Mix (formerly Service Rock Products). This facility is also located over 8.5 miles from the PHPP. There are two primary sets of emissions at the facility: sources involved in the concrete batching process, and a number of portable engines that are moved to various locations on the property to provide power as needed. As a result, these two processes were each represented by an area source with the same source characteristics as the fugitive emission sources used to represent construction activities at PHPP. The cement batching process was represented by a source with an area of 8,000 m2 covering the area where the majority of the batching process occurs, while the remaining emissions were characterized by a source with an area of 45,000 m2. The source characteristics and emissions for Granite Rock Construction are shown in Table 2-4.

Figure 2-1 Relative Location of PHPP, Non-Project Sources, and Division Street Monitor

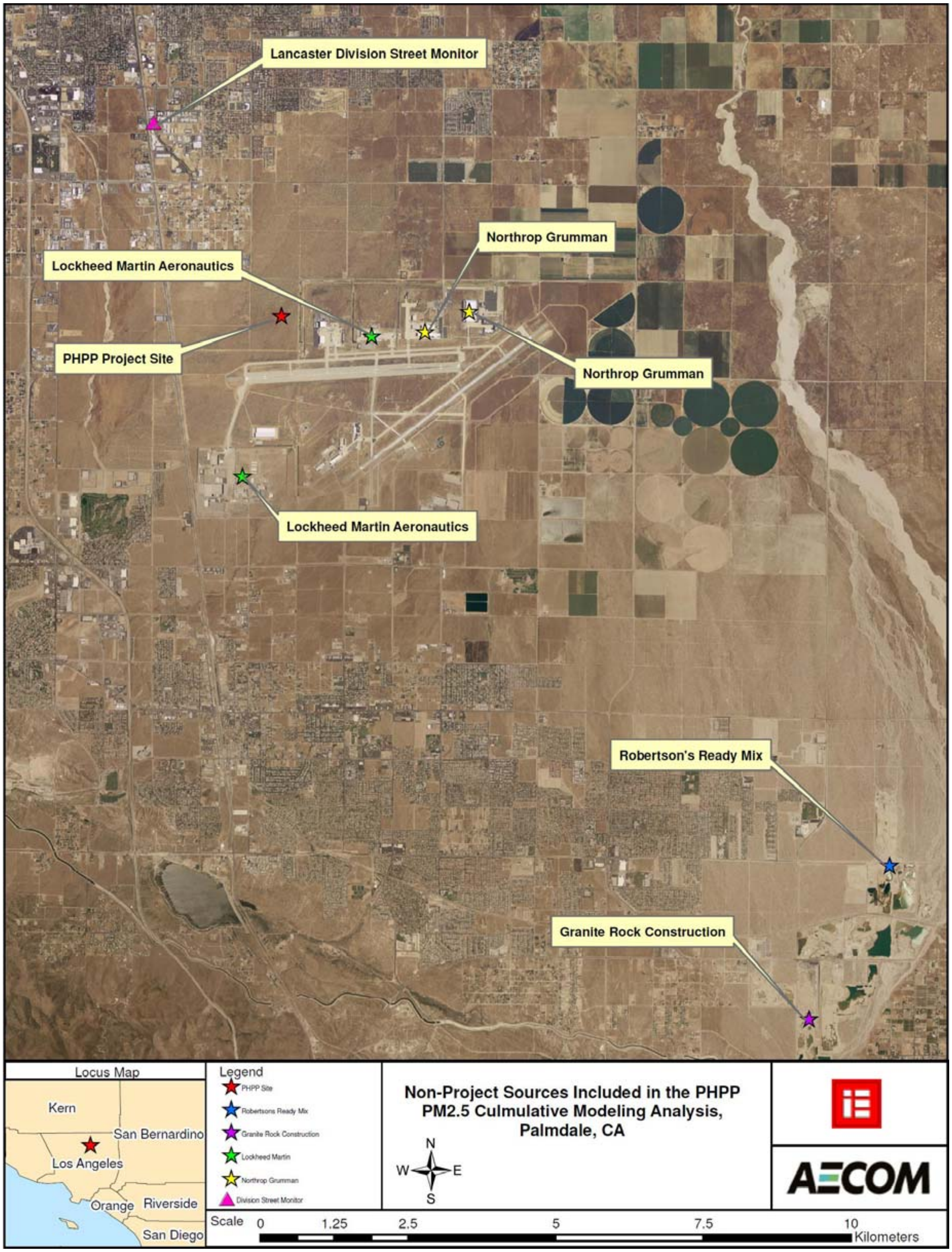

Figure 2-2 Lockheed Martin and Northrop Grumman Sources included in the Modeling Analysis

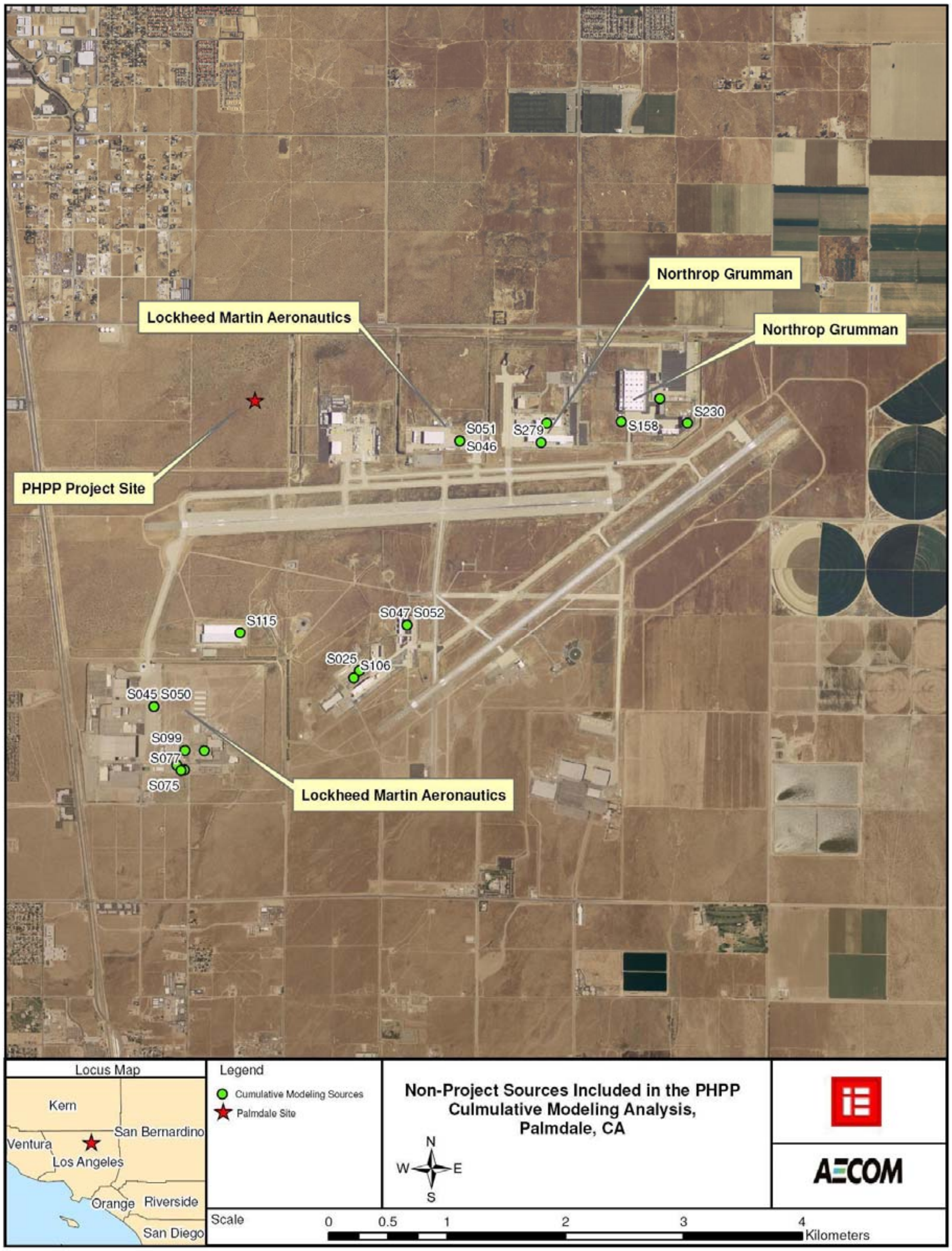

Table 2-1 Lockheed Martin Aeronautics Sources

Point Sources (annual runs only)

Source ID	UTM Easting (NAD27)	UTM Northing (NAD27)	Base Elev. (m)	Stack Hgt. (m)	Temp (°K)	Exit Vel. (m/s)	Exit. Diam. (m)	PM2.5 (lb/hr)	PM2.5 (tpy)
S075	398078.7	3830369.0	746.76	3.052	505.4	22.77	1.22	0.18	0.77
S077	398050.6	3830366.0	746.76	5.351	505.4	21.59	1.22	0.05	0.22
S099	398083.6	3830535.0	746.76	3.052	477.6	20.01	1.22	0.09	0.40
S106	399511.6	3831148.0	746.76	2.000	505.4	8.50	0.92	0.05	0.24
S116	398247.6	3830534.0	746.76	2.000	297.0	20.01	1.22	0.05	0.20

Volume Source

Source ID	UTM Easting (NAD27)	UTM Northing (NAD27)	Base Elev. (m)	Rel. Hgt. (m)	Sigma-Y	Sigma-Z	PM2.5 (lb/hr)	PM2.5 (tpy)
S055	398013.6	3830411.0	746.76	2.75	1.52	1.52	6.50	1.95

Table 2-2 Northrop Grumman Sources

Point Sources

Source ID	UTM Easting (NAD27)	UTM Northing (NAD27)	Base Elev. (m)	Stack Hgt. (m)	Temp (°K)	Exit Vel. (m/s)	Exit. Diam. (m)	PM2.5 (lb/hr)	PM2.5 (tpy)
S215 (annual only)	402103.5	3833516.0	789.30	10.67	466.48	18.29	0.31	0.12	0.51
S216 (annual only)	402104.7	3833516.0	789.30	10.67	466.48	18.29	0.31	0.12	0.51
S279 (annual only)	401099.4	3833145.0	789.30	6.10	288.71	3.05	3.05	0.96	4.21
S230 (24-hour only)	402337.0	3833310.0	789.30	12.20	299.82	0.10	3.05	0.01	0.41

Volume Source

Source ID	UTM Easting (NAD27)	UTM Northing (NAD27)	Base Elev. (m)	Rel. Hgt. (m)	Sigma-Y	Sigma-Z	PM2.5 (lb/hr)	PM2.5 (tpy)
S158 (24-hour only)	401777.9	3833322.0	789.30	12.20	2.84	5.67	0.01	0.05

Table 2-3 Granite Rock Construction Sources

Area Source

Source ID	UTM Easting (NAD27)	UTM Northing (NAD27)	Base Elev. (m)	Rel. Hgt. (m)	Init Sigma-Z (m)	Total Area (m^2)	PM2.5 (lb/hr)	PM2.5 (tpy)
GC	407476.8	3821419.8	859.54	2.0	2.13	54,000	6.18	27.1

Table 2-4 Robertson's Ready Mix Sources

Area Source

Source ID	UTM Easting (NAD27)	UTM Northing (NAD27)	Base Elev. (m)	Rel. Hgt. (m)	Init Sigma-Z (m)	Total Area (m^2)	PM2.5 (lb/hr)	PM2.5 (tpy)
RRM_1 (batch process)	408757.2	3825360.2	818.39	2.0	2.13	8,000	3.36	14.7
RRM_2 (all other sources)	408762.5	3824316.1	818.39	2.0	2.13	45,000	3.66	16.0

2.1.3 Modeling Methodology

On March 23, 2010, EPA issued a memo regarding the modeling of PM2.5 indicating that the use of PM10 modeling is no longer an acceptable means of demonstrating NAAQS compliance for PM2.5. Instead the following procedures for modeling PM2.5 were identified:

- 24-hour PM2.5: The high-1st-high impact at each receptor averaged over the number of years included in the modeling exercise, added to the average of the 98th percentile ambient background concentrations for the most recent 3-years available at a nearby monitoring site.
- Annual PM2.5: The highest average of the modeled annual averages over the period of years included in the modeling, added to the highest annual average background averaged over the most recent 3-years available at a nearby monitoring site.

Based on this recent guidance, the supplemental cumulative PM2.5 modeling for PHPP was performed using the methodology described above. The full text of the EPA memo can be found at: http://www.epa.gov/region07/air/nsr/nsrmemos/pm25memo.pdf. Although this methodology was followed, a discussion is provided in Section 2.2.5 below as to why this guidance is overly conservative.

2.1.3.1 Sources, Stack Parameters, and Emissions for PHPP

In this modeling analysis, the stack parameters and emissions data for the PHPP sources used were the same as in PSD application submitted in April 2009, except for solar field maintenance vehicle emissions that were slightly updated in responses to CEC data requests submitted on May 1, 2009. For all PHPP sources, it was also conservatively assumed that the PM2.5 emissions for PHPP sources were equivalent to their respective PM10 emissions with the exception of the solar field maintenance vehicular fugitive emissions. AERMOD version 09292 was used in this analysis.

2.1.3.2 Meteorological Data

The meteorological data used in this analysis were the same as was used in the PSD Application modeling. Three years of surface observation data collected at the Palmdale Regional Airport in Palmdale (2002-2004), along with concurrent upper air data from Mercury Desert Rock Airport in Mercury, Nevada, were used in the modeling analysis.

2.1.3.3 Ambient Background Data

Ambient background data for PM2.5 are available from the monitor located at 43301 Division St. in Lancaster, California, located approximately two miles from the PHPP site, as shown in **Figure 2-1**. Background data from 2006-2008 were used as the data available on the AIRS database website (http://www.epa.gov/air/data/geosel.html) are not yet complete for 2009 (note, data for 2005-2007 were used in the PSD Application). For the 24-hour period, the 3-year average of the 98th percentile values was used. For the annual period, the 3-year average annual mean was used.

The PM2.5 background data for the Division Street Monitor are shown in **Table 2-5**.

Table 2-5 Ambient PM2.5 Background Concentrations at 43301 Division St. Lancaster

Pollutant	Period	Measure	PM2.5 Ambient Background (μg/m^3)				
			2006	2007	2008	Max.	Avg.
PM2.5	24-hour	1st-high	18	25	24	25	22
		2nd-high	13	20	13	20	15
		98th %	13	20	24	24	19
	Annual	Mean	7.4	8.0	7.2	8.0	7.5

2.1.3.4 Receptor Grid

The previous PM2.5 modeling in the PSD Application determined that the maximum impacts occur close to the PHPP. Therefore, the receptor spacing used within the modeling area is as follows:

- 50 m spacing along the PHPP facility fence line.
- 100 meter (m) spacing to 3 km from the plant centroid,
- 250 m spacing to 5 km from the plant centroid, and
- 500 m spacing to 10 km from the plant centroid.

Additionally, during the modeling analysis performed for the AFC for the project, it was discovered that both the Lockheed Martin (for 24-hour PM2.5) and Northrop Grumman (for annual PM2.5) facilities indicated large impacts at receptors within their own property boundaries. However, a facility may not contribute to an air quality impact within its own ambient air barrier[1]. Therefore, two additional receptor grids were created, one without the receptors located on the Lockheed Martin properties, and one without the receptors located on the Northrop Grumman properties. Two sets of model runs were done for each PM2.5 modeling period: one containing all of the emission sources for all facilities but excluded those receptors on the Lockheed property (24-hour PM2.5) or Northrop property (for annual PM2.5), and another with the whole receptor grid but excluding the Lockheed or Northrop emissions (for 24-hour and annual PM2.5 respectively). The highest modeled impact from the two runs was then used in comparison with the applicable NAAQS.

The receptor grid used in these model runs is shown in **Figure 2-3**.

2.1.4 Results and Discussion

The results of the cumulative PM2.5 modeling are shown in **Table 2-6**. In the table, the average of the maximum modeled high-1st-high over the three years by receptor is summed with the average of the 98th percentile ambient background values for the 24-hour period, and the maximum annual impact over the three years is added to the average annual mean ambient background averaged over three years. The results are then compared to the 24-hour NAAQS for PM2.5 (35 micrograms per cubic meter [μg/m^3]) and annual CAAQS for PM2.5 (12 μg/m^3). As shown in the table, the cumulative impacts for both periods are below their respective standard and thus compliance is demonstrated.

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[1] 40 CFR § 50.1(e) and 36 Federal Register 22384 (November 15, 1971)

Note that the modeled impact from PHPP sources alone, when calculated using the conservative methodology described in section 2.2.2, decreases from 12.73 $\mu g/m^3$ as described in the March, 2009 PSD Application, to 12.57 $\mu g/m^3$. Thus, the non-PHPP sources contribute only 0.01 $\mu g/m^3$ to the total impact.

The modeling and supporting files used in this analysis are included in **Appendix A**.

Table 2-6 PHPP Cumulative PM2.5 Modeling Results

Pollutant	Averaging Period	AERMOD Predicted Concentrations ($\mu g/m^3$)		Back-ground [2] ($\mu g/m^3$)	Cumulative Modeled + Background ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
		PHPP alone [1]	PHPP with Cumulative Sources			
PM2.5	24-hour	12.57	12.58	19.0	31.6	35
	Annual	1.2	1.3	7.5	8.8	15[3]

1. High-1st-high value; see discussion below, high-8th-high 24-hour value is 8.92 $\mu g/m^3$
2. 98th percentile value from Table 2-5
3. The annual PM2.5 CAAQS is 12 $\mu g/m^3$, and there is no separate 24-hour PM2.5 CAAQS

Historically, NAAQS have been written in the form that the standards are not to be exceeded more than once per year. Based on this "form" of the standard, the highest observed concentration in a given year, even if over the standard, would be allowed, but if the second highest observed value exceeded the standard, it is considered a violation. In modeling terms, the highest concentration modeled in a receptor grid is called the "high-1st-high", i.e., the highest concentration at the highest receptor, while the second highest concentration is called the "high-2nd-high", and so on. Therefore, in order to show compliance with most of the NAAQS, the modeled high-2nd-high is added to the background value, and must be below the applicable NAAQS.

In the case of the PM2.5 NAAQS, the 24 hour standard is attained when 98 percent of the daily concentrations, averaged over three years, are equal to or less than the standard. The value used to determine compliance with the 24-hour PM2.5 standard is called the 98th percentile value. In a modeling analysis, the 98th percentile value is approximately the same as the 8th highest value at the maximum receptor, or the high-8th-high. The methodology described for the modeling of 24-hour PM2.5, i.e., use of the high-1st-high impact at each receptor averaged over the years included in the modeling exercise, is both inconsistent with the form of the standard and also appears to be overly conservative. The memo provides no justification for the use of high-1st-high rather than the 98th percentile (high-8th-high), which is consistent with the form of the standard, or any other value in between (high-2nd-high being the standard for cumulative modeling assessments of most other pollutants, for example). The memo infers to an extent that the formation of secondary PM2.5 requires more than the high-8th-high be used to preserve conservatism; however, it was shown by Heinold et. al (AECOM, 2003) that in the near field, where PM2.5 impacts are likely to be the highest, primary PM2.5 emissions dominate the modeled impacts, accounting for as much as 99 percent of the total modeled concentrations.

Additionally, as shown below, the current AERMOD model change bulletin (EPA web site) already provides the proper approach for computing the modeled source impacts for the 24-hour PM2.5 NAAQS.

"The following changes have been made to ensure consistency with the current PM NAAQS:

a) Added special processing for PM2.5 to calculate design values in accordance with the PM NAAQS. The design value for 24-hour averages is based on the high-eighth-high (H8H) averaged over N years, as an unbiased surrogate for the 98th percentile. The long-term design value for PM2.5 is based on the highest annual average concentration averaged over N years using the ANNUAL keyword on the AVERTIME card.

Based on the above discussion, AECOM believes that a refined modeling analysis should more properly use the high-8th-high modeled concentration added to the three year average 98th percentile background concentration. The model is already sufficiently conservative to be protective of the PM2.5 NAAQS. With this approach, the maximum cumulative PM2.5 concentration (including background) would be 28.6 $\mu g/m^3$.

2.2 PM2.5 Increment Analysis

On September 21, 2007, EPA published a Proposed Rule in the Federal Register (72 Fed. Reg. 54144) regarding *Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5)—Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC)*. Among other requirements, the Proposed Rule contemplates three different "options" for adopting PM 2.5 "increments" pursuant to the PSD program. As of the date of this submission, the Proposed Rule has not been finalized. (*See* EPA Docket for Proposed Rule, available at: http://www.regulations.gov/search/Regs/home.html#docketDetail?R=EPA-HQ-OAR-2006-0605.) Thus, the proposed PM 2.5 increment has not been finalized and should not be required for a pending application that was originally submitted to the EPA on April 1, 2009**.**

Under the Proposed Rule, applications deemed complete prior to the effective of the Final Rule do not need to satisfy the requirements of the Final Rule. (*See* 72 Fed. Reg. 54143.) In other words, if the PHPP application is deemed complete before the Final Rule becomes effective, the PM 2.5 increment would not be applicable.

Even after the EPA promulgates the Final Rule (which has not occurred), the Final Rule may not become effective for as long as another year pursuant to Section 166(a) of the Clean Air Act. (*See* 72 Fed. Reg. 54142.) The EPA has requested comment on using a shorter 60-day period for the effective date. (*Id.*) Even with the shorter approach, there would still be a two-month period after the Final Rule is promulgated before it becomes effective. If the PHPP application is deemed complete before or during this period, the PM 2.5 increment would not be applicable.

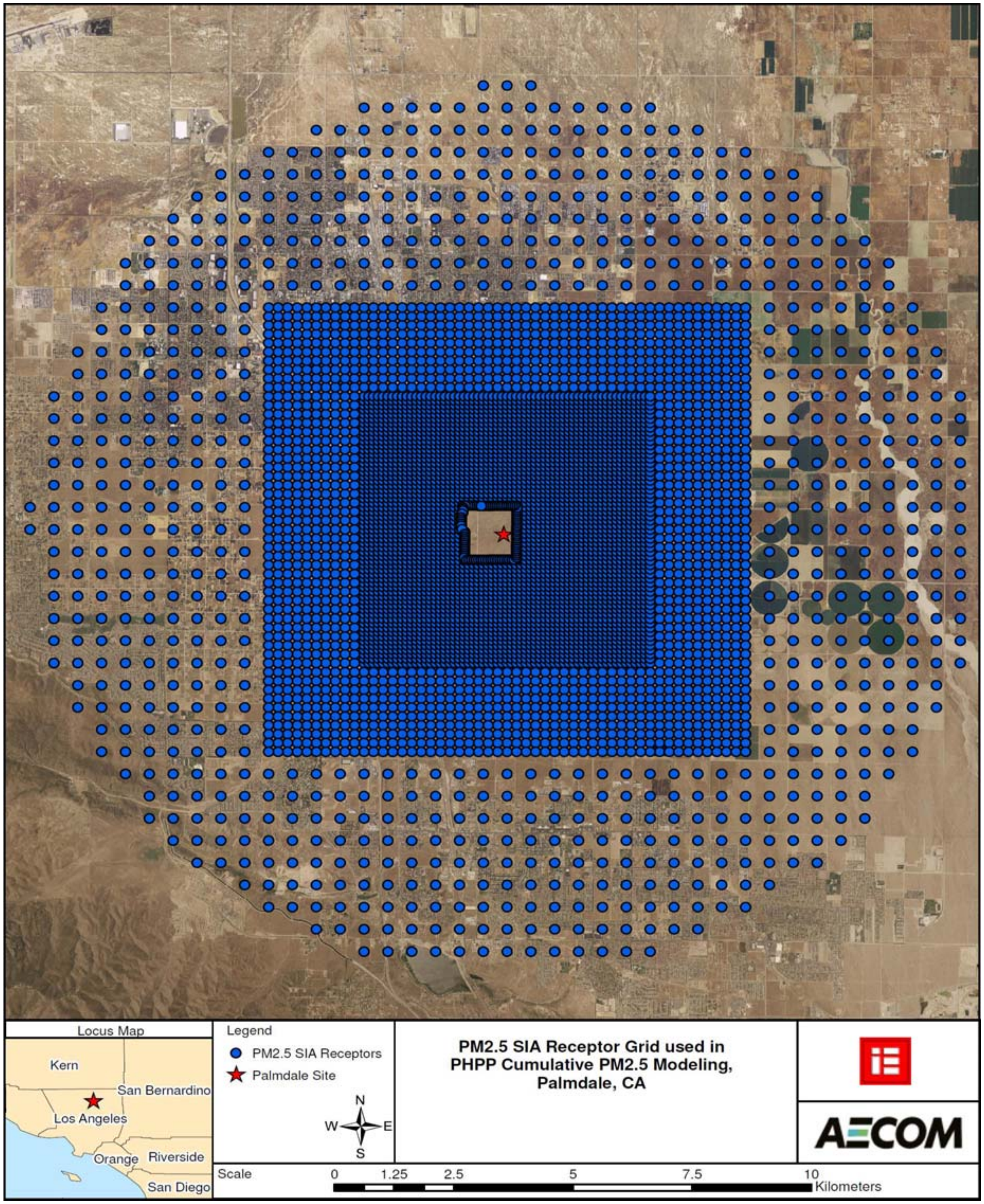
Under the Proposed Rule, the EPA cannot deny deeming an application complete because it does not include a PM2.5 increment analysis that is not yet required. (*See* proposed 40 CFR 52.21(i)(11), at 72 Fed. Reg. 54154 [referring to an application that is "otherwise" complete].) Thus, because the PHPP application is not required to conform to the Final Rule until it becomes effective, the EPA should not base a completeness determination on the absence of a PM 2.5 increment analysis that is not yet required.

2.3 References for Section 2

EPA web site: http://www.epa.gov/scram001/7thconf/aermod/aermod_mcb1.txt

Heinold, D., S. Toole, and S. Heisler (AECOM), 2003. Evaluating the Impacts of a Power Plant's Emissions on PM2.5, A&MWA Paper #69646, presented at the 96th annual conference.

Figure 2-3 Receptor Grid Used in PM2.5 Cumulative Modeling Analysis



3.0 1-Hour NO_2 NAAQS Modeling

3.1 Regulatory Background

On April 12, 2010, the federal 1-hour NO_2 NAAQS became effective. The EPA describes this new NAAQS as follows:

> "On January 22, 2010, EPA announced a new hourly NO_2 standard of 100 ppb based on the 3-year average of the 98th-percentile of the annual distribution of daily maximum 1-hour concentrations. The final rule for the new hourly NAAQS was published in the Federal Register on February 9, 2010, and will be effective on April 12, 2010".(http://www.epa.gov/air/nitrogenoxides/actions.html#jan10).

EPA released a Support Center for Regulatory Atmospheric Modeling (SCRAM) bulletin on the modeling of the new 1-hour NO_2 NAAQS on February 25, 2010. That bulletin can be found at: http://www.epa.gov/ttn/scram/no2_hourly_NAAQS_aermod_02-25-10.pdf. EPA released another memorandum titled "Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program" on June 28th 2010 in an attempt to further clarify the modeling methodology for the 1-hour NO_2 NAAQS. That memorandum can be found at: http://epa.gov/Region7/air/nsr/nsrmemos/appwno2.pdf. In addition, Roger Brode and Dan DeRoecke of the EPA Office of Air Quality Planning and Standards (OAQPS) held a Webinar on July 15, 2010 where this new NAAQS was discussed from both a policy and dispersion modeling point of view. EPA indicated during this Webinar that further guidance would be forthcoming, as there remains a great deal of uncertainty in the performance of this analysis. In the meantime, EPA indicated that applicants should use their professional judgment in the conduct of these analyses.

3.2 Modeling Methodology

Because the EPA preferred air dispersion model, AERMOD, does not output results in a format that can be compared to the form of the standard, AECOM developed an AERMOD post-processor that uses binary output produced by a 1-hour NO_2 AERMOD run and processes the data for comparison to the 1-hour NO_2 NAAQS. The "POST-1HR" postprocessor fully complies with the modeling procedure outlined in the EPA's SCRAM bulletin and performs the following steps:

- Using binary output from AERMOD, the hourly impacts for each receptor for each year processed are read in, and the time-matched ambient background concentration for each hour is added to the modeled impact to produce a total concentration at each receptor for each hour.
- Using the hourly data, the highest total impact at each receptor for each day is then determined. This is the "maximum daily impact" referenced in the form of the standard.
- For each receptor, the 98th percentile of the maximum daily impacts is determined for each year modeled.
- Finally, the 98th percentile of the maximum daily impacts is averaged over the three years modeled to determine the final concentration for comparison to the standard.

The Ozone Limiting Method (OLM) option in AERMOD was used as a refined technique to more accurately model the conversion of NOx emissions to ambient NO_2 concentrations. The OLM analysis is Tier 3 of the EPA's multi-tiered screening approach for estimating NO_2 impacts from point sources as provided in the Guideline for Air Quality Models (GAQM). In the OLM analysis, 10 percent of the NOx emissions from the source are assumed to convert to NO_2 (i.e., fraction associated with thermal conversion) while the remaining fraction of NOx (90 percent) is converted based on available ambient ozone concentrations. That is, conversion of the remaining 90 percent of NOx to NO_2 is limited based on the availability of ozone, and the remaining converted NO_2 is equivalent to the ambient ozone concentration. These are the default values used in AERMOD for the OLM method stack-tip conversion of NOx to NO_2. The default value was used because there is currently no guidance from EPA or other data available on varying the stack tip conversion based on the different types of combustion sources and operating scenarios. These computations are conducted internally in AERMOD on an hourly basis and require representative hourly monitored ozone that is concurrent to the meteorological data used in the modeling. For this analysis, three years of monitored ozone concentrations from the Lancaster Division Street monitoring station were used that were concurrent with the three years (2002-2004) of meteorological data (see Section 2.2.3.2) used in the modeling.

3.2.1 Normal Operations

AECOM applied the "POST-1HR" post-processor to the PHPP 1-hour NO_2 modeling for normal operations to demonstrate compliance with the 1-hour NO_2 NAAQS. As described in the PSD Application, concurrent hourly ambient background concentrations for NO_2 were taken from the Lancaster Division Street monitoring station. The Division Street monitor is about two miles from the PHPP site, located well within the city limits of Lancaster and within 200 yards of the Sierra Highway. Because of it's proximity to the Project site, it's location within a more urban area than the Project site, and the fact that it is situated in an area that experiences much denser vehicular traffic than the Project site, it is assumed that the Division Street monitor accurately and conservatively reflects the 1-hour NO_2 background at the PHPP site.

PHPP emissions data for NOx and stack parameters used for this analysis are provided in the March 2009 PSD Application.

After processing with the "POST-1HR" post-processor, the 3-year average of the 98th percentile maximum daily 1-hour NO_2 impacts for normal operations, including ambient background concentrations based on OLM, was determined to be 175.3 μg/m^3 (93.2 ppb). The maximum contribution by Project sources alone was 106.9 μg/m^3 (56.8 ppb).

3.2.2 Startup and Shutdown Analysis

During startup and shutdown of combustion turbine generators, emissions of NOx and CO are much higher than the emissions of these pollutants during normal operations. Combined-cycle power plants such as PHPP must be brought on-line slowly while the steam turbine generator warms up. The emissions control systems (e.g., selective catalytic reduction system for NOx control) is not utilized during this period as the catalyst must be at a sufficient temperature to be effective. While PHPP will have higher NOx and CO emissions during startup, this power plant's emissions will be much lower than many combined-cycle plants due to the use of the Rapid Start Process (RSP), which minimizes the time needed in startup mode, and hence greatly reduces the emissions during startup.

In the March 2009 PSD Application, an analysis of impacts during CTG startup and shutdown was provided for CO emissions from PHPP since there were short-term (1-hour and 8-hour) NAAQS for

CO (Section 6.1.4). Since the 1-hour NO_2 NAAQS only became effective in April 2010, a modeling analysis[2] for startup or shutdown emissions was not included for this pollutant in the PSD Application. However, because there is a 1-hour NO_2 CAAQS, an analysis for NOx emissions during startup and shutdown had been provided in the PHPP AFC (Section 5.2.4.2.2).

As described in the AFC, a worst-case emission rate was found to occur during shutdown events, which can last up to half an hour. Therefore, the maximum hourly emissions analyzed consisted of a half hour at the maximum normal operations emission rate and a half hour at the shutdown emission rate as follows:

Maximum NO_2 emissions = (0.5 hours x 16.6 lb/hr) + 57 lb/event (shutdown) = 65.3 lb/hr per turbine.

The stack parameters (as given in the PSD Application) were an exit temperature of 173.5 ^{o}F and an exit velocity of 31.76 ft/sec (based on 20 percent load). The modeling methodology, using OLM and the "POST-1HR" post-processor, was applied as described above for normal operations.

For startup / shutdown periods, the 3-year average of the 98th percentile maximum daily 1-hour NO_2, including ambient background concentrations based on OLM, was determined to be 180.3 μg/m^3 (95.9 ppb). The maximum contribution by PHPP sources alone during startup / shutdown was 136.4 μg/m^3 (72.5 ppb).

3.3 Summary of Results

As the standard is 100 parts per billion (ppb), the impact of PHPP including background is below the standard and, therefore, compliance is demonstrated for both normal operations and startup / shutdown periods.

The "POST-1HR" post-processor, along with all files used in the processing, is included in the electronic modeling archive provided as **Appendix A**.

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[2] Although a modeling analysis for startup and shutdown was not included in the March 2009 PSD Application for NO_2 impacts, a BACT analysis was included in the March 2009 PSD Application for startup and shutdown emissions.

4.0 Visibility Analysis

PSD regulations require an analysis of visibility impairment at Class I areas be prepared for PSD projects. Visibility impairment for Class I areas within 50 km of a proposed PSD project is called plume blight and for Class I areas beyond 50 km is referred to as regional haze. Potential impacts to visibility were analyzed at several Class I areas located within 100 km of the PHPP and the results presented in the PSD Application submitted on April 1, 2009. In addition to those analyses, EPA requested in March 2010 that "sensitive" Class II areas located within 50 km also be considered. No specific definition was provided as to what would be considered "sensitive" Class II Areas; however, these were assumed to be areas such as federal wilderness areas and State parks.

In order to determine prospective Class II areas for consideration, several data sources were used:

1. Google Earth in order to catalogue parks that were nearby to the project site.
2. U.S. Forest Service website: http://www.fs.fed.us/
3. The California State Parks website: http://www.parks.ca.gov/

From these sources, five sites were identified as candidates for inclusion in the expanded visibility analysis, as follows:

- Sheep Mountain Wilderness Area (WA)
- Saddleback Butte State Park
- Antelope Valley Indian Museum State Park
- Antelope Valley California Poppy State Reserve
- Arthur B. Ripley Desert Woodland

All of these five areas are within 50 km of PHPP as shown in **Figure 4-1**. The plume visibility analysis was conducted with the most current version of EPA's screening model VISCREEN to determine if Project emissions will impair visibility in the five areas identified for analysis. VISCREEN was applied with the guidance provided in EPA's Workbook for Plume Visual Impact Screening and Analysis (Workbook). As such, the VISCREEN model was applied to estimate two visual impact parameters, plume perceptibility (ΔE) and plume contrast (C_p). Screening-level guidance indicates that, for PSD Class I areas, values above 2.0 for ΔE and +/- 0.05 for C_p are considered perceptible. Note that the Class II areas being assessed in this analysis should not be held to the same stringent guidance levels.

The Workbook offers two levels of analyses. A Level 1 screening analysis is the most simplified and conservative approach employing default meteorological data with no site-specific conditions. A Level 2 analysis takes into account representative meteorological data and site-specific conditions such as complex terrain. Initially, the Level 1 analysis was conducted and indicated ΔE and C_p values were above the screening thresholds for all five sites. Therefore, a Level 2 analysis was conducted.

A Level 2 analysis was conducted with the same three years of meteorological data used in the Class I air quality impacts analysis. In addition, per Workbook guidance, the stability class of the Sheep Mountain WA was reduced by one class (less stable) because the terrain elevation differences between the facility (stack-top) location and Sheep Mountain WA is more than 500 meters (m). The maximum elevation at Sheep Mountain WA is 3,068 m above mean sea level (amsl) at its highest point (Mt. Baldy). The stack-top elevation of the project source is 811 m amsl. This results in a difference in elevation of 2,257 m. The other four Class II areas all have base elevations within 500 m of the PHPP stack top elevation. Therefore, the stability class was unchanged from the value determined in meteorological data frequency analysis.

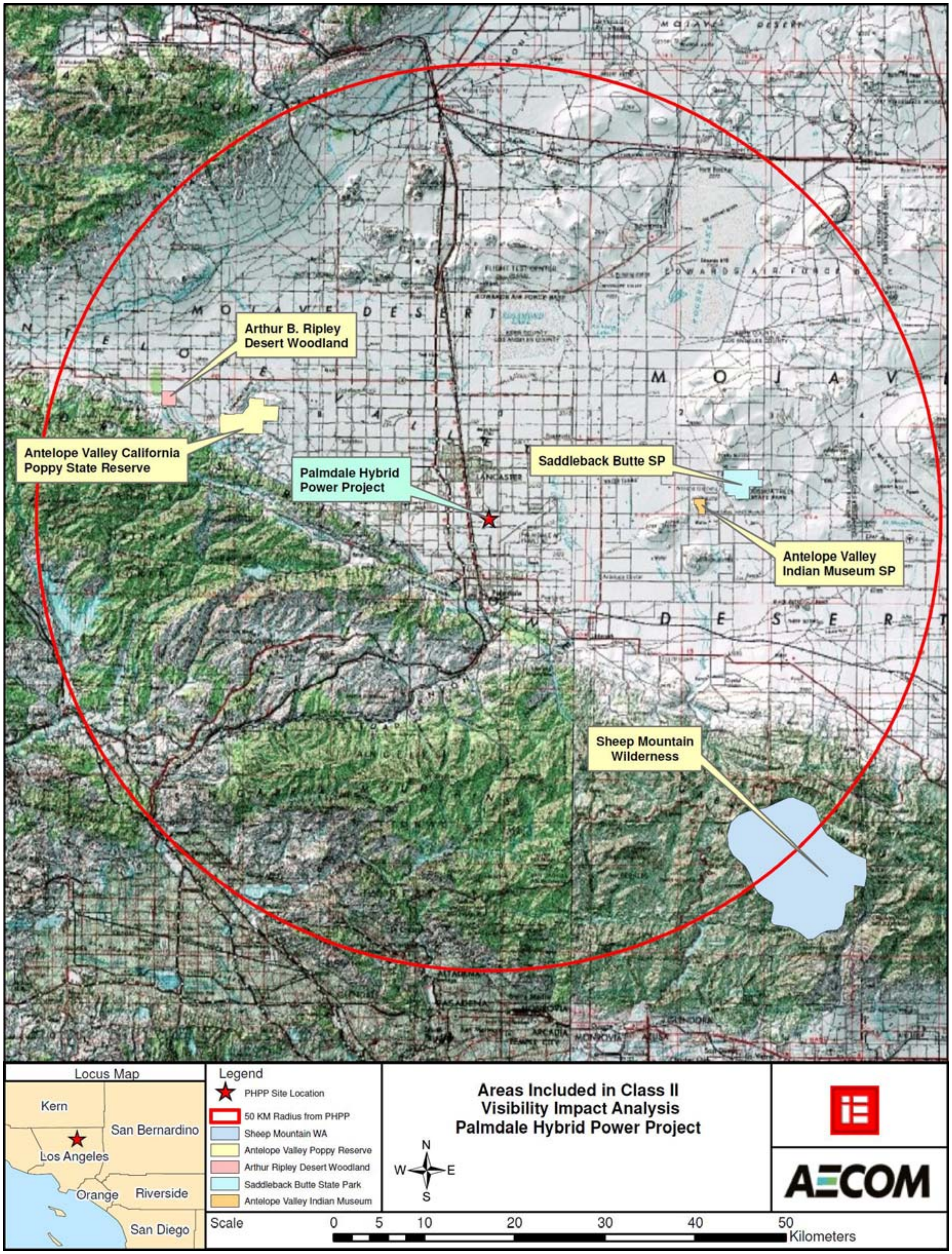
The source data required by VISCREEN are total NOx emissions (33.20 pounds per hour [lb/hr]) and particulate emissions (36.00 lb/hr) for the CTGs. Included in the particulate emissions were emissions of elemental carbon (EC) (9.00 lb/hr) and sulfate (SO_4) (0.99 lb/hr) emissions. The speciated PM10 emissions where derived according to procedures referenced in the PHPP Class I modeling protocol and conform to recommendations by the National Park Service (NPS). The NPS guidance specifies that of the total PM10, 25 percent should be considered filterable PM10 and 75 percent should be considered condensable PM10. The filterable PM10 is conservatively assumed to be EC, while the condensable PM10 (minus the primary sulfate) is conservatively assumed to be organic aerosols. It was assumed that all NOx is present as NO_2. The 22.5 degree (°) wind direction sectors that would transport emissions from the PHPP toward the five areas chosen for analysis, along with the closest and farthest distances from those areas to the proposed PHPP site, are shown in **Table 4-1**. The locations of the areas relative to the PHPP site are shown in **Figure 4-1**.

Table 4-1 Class II Areas Included in VISCREEN Analysis

Area Name	22.5° Wind Sector	Closest Distance to PHPP (km)	Furthest Distance from PHPP (km)	Worst Case Stability Class	Worst Case Wind Speed (m/s)
Sheep Mountain Wilderness Area	303.75-326.25	42.95	59.63	E[1]	4
Saddleback Butte State Park	258.75-281.25	26.13	30.65	F	3
Antelope Valley Indian Museum State Park	258.75-281.25	22.80	24.04	F	3
Antelope Valley California Poppy State Reserve	101.25-123.75	25.59	31.84	E	5
Arthur B. Ripley Desert Woodland	101.25-123.75	36.64	38.67	E	5

1. Because Sheep Mountain Wilderness Area is more than 500 m above the stack top elevation of PHPP, this source was modeled at one stability class less stable, i.e., class D, per the Workbook.

Figure 4-1 Areas Included in the Visibility Analyses



Based on this information, and the three years of meteorological data, a table of joint frequency of occurrence of wind speed, wind direction, and stability class was developed for each of the five areas analyzed as outlined in the Workbook. The dispersion conditions, defined by wind speed and stability class, were ranked by evaluating the product of σ_y, σ_z, and u, where σ_y and σ_z are the Pasquill-Gifford horizontal and vertical diffusion coefficients for the given stability class and downwind distance and u is the wind speed. The dispersion conditions were then ranked in ascending order according to the value of $\sigma_y \sigma_z u$ as shown in **Tables 4-2** through **4-6**.

According to the Workbook, VISCREEN is to be applied with the worst-case meteorological conditions that have a $\sigma_y \sigma_z u$ product with a cumulative probability of one percent. That is, the dispersion condition is selected such that the sum of all frequencies of occurrence of conditions worse than this condition totals one percent. Note that as recommended by the Workbook, dispersion conditions that result in greater than 12 hours of plume transport time are discounted from the analysis, since it is unlikely that steady-state plume conditions would persist for more than 12 hours.

The worst-case dispersion conditions with a cumulative frequency of one percent from **Tables 4-2** through **4-6** are also given in **Table 4-1**. As discussed previously, the stability class used for Sheep Mountain WA was reduced from E to D (slightly less stable), as recommended by Workbook for cases when the terrain relief is greater than 500 meters as compared from stack top to elevations in the Class II area. As recommended by the FLAG guidance (FLM, 2000), a visual range of 246 km was used. A visual range of 246 km was used for the San Gabriel Wilderness Area in the PSD application, and because it is the closest Class I area to the PHPP, this value was used for all of the Class II areas included in this analysis. While the visual range is specific to a particular Class I area, Class I areas within the same region typically have visual ranges that are very similar. Additionally, by definition Class I areas are held to more stringent standards than Class II areas and thus the use of 246 km as a visual range for Class II areas in the vicinity of PHPP is a conservative measure.

The VISCREEN results are summarized in **Table 4-7**. VISCREEN provides results of ΔE and C_p for both sky and terrain backgrounds. The results are below the significance criteria in all cases with the exception of Saddleback Butte State Park and Antelope Valley Indian Museum State Park when the observer looks at a terrain background. For all other cases, the plume is expected to be imperceptible. As a further refinement, plume perceptibility was examined for daylight hours only (6 am – 6 pm) at Saddleback Butte State Park and Antelope Valley Indian Museum State Park. Per **Tables 4-2** and **4-3**, the worst-case daytime meteorological conditions with a cumulative probability of 1 percent are stability class D with a wind speed of 5 meters per second (m/s). VISCREEN was rerun using these values to determine plume perceptibility and contrast for those two sites during daylight hours. The results, shown in **Table 4-8**, indicate that the plume will not be perceptible at either site during daylight hours.

Table 4-2 Dispersion Condition Frequency Analysis – Sheep Mountain Wilderness Area - Sector 303.75º – 326.25º

Dispersion Condition		$\sigma_y\sigma_z u$	Transport Time	Frequency By Time of Day (%)				Cumulative Frequency By Time of Day (%)			
Stability Class	Wind Speed (m/s)	(m^3/s)	(hours)	0-6	6-12	12-18	18-24	0-6	6-12	12-18	18-24
F	1	74369	24	0.335	0.046	0.000	0.319	0.000	0.000	0.000	0.000
F	2	148739	8	0.289	0.030	0.000	0.213	0.289	0.030	0.000	0.213
E	1	212980	24	0.030	0.122	0.030	0.122	0.289	0.030	0.000	0.213
F	3	223108	5	0.502	0.076	0.000	0.578	0.791	0.106	0.000	0.791
E	2	425960	8	0.015	0.106	0.000	0.046	0.806	0.213	0.000	0.836
D	1	592377	24	0.076	0.137	0.076	0.046	0.806	0.213	0.000	0.836
E	3	638940	5	0.091	0.122	0.030	0.152	0.897	0.335	0.030	0.988
E	4	851920	3	0.122	0.046	0.030	0.304	1.019	0.380	0.061	1.293
E	5	1064900	3	0.061	0.000	0.091	0.228	1.080	0.380	0.152	1.521
D	2	1184755	8	0.030	0.198	0.015	0.000	1.110	0.578	0.167	1.521
D	3	1777132	5	0.030	0.228	0.106	0.030	1.141	0.806	0.274	1.551
D	4	2369509	3	0.122	0.122	0.106	0.030	1.262	0.928	0.380	1.582
D	5	2961886	3	0.046	0.046	0.030	0.030	1.308	0.973	0.411	1.612
D	6	3554264	2	0.046	0.061	0.137	0.152	1.353	1.034	0.547	1.764
D	7	4146641	2	0.000	0.274	0.213	0.137	1.353	1.308	0.760	1.901
D	8	4739019	2	0.030	0.152	0.259	0.015	1.384	1.460	1.019	1.916

Notes: m/s = meters/second m^3/s = cubic meters/second

Table 4-3 Dispersion Condition Frequency Analysis – Saddleback Butte State Park - Sector 258.75º – 281.25º

Dispersion Condition		$\sigma_y\sigma_z u$	Transport Time	Frequency By Time of Day (%)				Cumulative Frequency By Time of Day (%)			
Stability Class	Wind Speed (m/s)	(m^3/s)	(hours)	0-6	6-12	12-18	18-24	0-6	6-12	12-18	18-24
F	1	41711	15	0.623	0.061	0.000	0.654	0.000	0.000	0.000	0.000
F	2	83422	5	0.730	0.061	0.000	0.502	0.730	0.061	0.000	0.502
E	1	115056	15	0.061	0.259	0.000	0.015	0.730	0.061	0.000	0.502
F	3	125132	3	1.262	0.091	0.030	1.293	1.992	0.152	0.030	1.794
E	2	230112	5	0.061	0.213	0.030	0.061	2.053	0.365	0.061	1.855
D	1	295291	15	0.046	0.304	0.000	0.015	2.053	0.365	0.061	1.855
E	3	345167	3	0.198	0.228	0.091	0.304	2.251	0.593	0.152	2.159
E	4	460223	2	0.547	0.015	0.046	0.973	2.798	0.608	0.198	3.133
E	5	575279	2	0.988	0.015	0.228	1.825	3.786	0.623	0.426	4.957
D	2	590583	5	0.061	0.106	0.046	0.015	3.847	0.730	0.471	4.973
D	3	885874	3	0.182	0.106	0.137	0.106	4.030	0.836	0.608	5.079
D	4	1181165	2	0.182	0.137	0.030	0.076	4.212	0.973	0.639	5.155
D	5	1476456	2	0.198	0.137	0.167	0.319	4.410	1.110	0.806	5.474
D	6	1771748	1	0.380	0.304	0.365	0.867	4.790	1.414	1.171	6.341
D	7	2067039	1	0.821	0.456	1.125	1.247	5.611	1.870	2.296	7.588
D	8	2362330	1	0.547	0.547	1.353	1.110	6.159	2.418	3.650	8.698

Table 4-4 Dispersion Condition Frequency Analysis – Antelope Valley Indian Museum SP - Sector 258.75º – 281.25º

Dispersion Condition		$\sigma_y\sigma_z u$	Transport Time	Frequency By Time of Day (%)				Cumulative Frequency By Time of Day (%)			
Stability Class	Wind Speed (m/s)	(m^3/s)	(hours)	0-6	6-12	12-18	18-24	0-6	6-12	12-18	18-24
F	1	35386	13	0.623	0.061	0.000	0.654	0.000	0.000	0.000	0.000
F	2	70771	4	0.730	0.061	0.000	0.502	0.730	0.061	0.000	0.502
E	1	96958	13	0.061	0.259	0.000	0.015	0.730	0.061	0.000	0.502
F	3	106157	3	1.262	0.091	0.030	1.293	1.992	0.152	0.030	1.794
E	2	193915	4	0.061	0.213	0.030	0.061	2.053	0.365	0.061	1.855
D	1	242501	13	0.046	0.304	0.000	0.015	2.053	0.365	0.061	1.855
E	3	290873	3	0.198	0.228	0.091	0.304	2.251	0.593	0.152	2.159
E	4	387830	2	0.547	0.015	0.046	0.973	2.798	0.608	0.198	3.133
E	5	484788	1	0.988	0.015	0.228	1.825	3.786	0.623	0.426	4.957
D	2	485002	4	0.061	0.106	0.046	0.015	3.847	0.730	0.471	4.973
D	3	727502	3	0.182	0.106	0.137	0.106	4.030	0.836	0.608	5.079
D	4	970003	2	0.182	0.137	0.030	0.076	4.212	0.973	0.639	5.155
D	5	1212504	1	0.198	0.137	0.167	0.319	4.410	1.110	0.806	5.474
D	6	1455005	1	0.380	0.304	0.365	0.867	4.790	1.414	1.171	6.341
D	7	1697506	1	0.821	0.456	1.125	1.247	5.611	1.870	2.296	7.588
D	8	1940007	1	0.547	0.547	1.353	1.110	6.159	2.418	3.650	8.698

Table 4-5 Dispersion Condition Frequency Analysis – Antelope Valley California Poppy State Reserve - Sector 101.25º – 123.75º

Dispersion Condition		$\sigma_y\sigma_z u$	Transport Time	Frequency By Time of Day (%)				Cumulative Frequency By Time of Day (%)			
Stability Class	Wind Speed (m/s)	(m^3/s)	(hours)	0-6	6-12	12-18	18-24	0-6	6-12	12-18	18-24
F	1	40674	14	0.167	0.000	0.000	0.350	0.000	0.000	0.000	0.000
F	2	81348	5	0.228	0.015	0.000	0.137	0.228	0.015	0.000	0.137
E	1	112081	14	0.015	0.015	0.000	0.015	0.228	0.015	0.000	0.137
F	3	122022	3	0.411	0.000	0.046	0.487	0.639	0.015	0.046	0.623
E	2	224161	5	0.015	0.030	0.015	0.015	0.654	0.046	0.061	0.639
D	1	286520	14	0.030	0.046	0.061	0.000	0.654	0.046	0.061	0.639
E	3	336242	3	0.076	0.015	0.046	0.046	0.730	0.061	0.106	0.684
E	4	448322	2	0.091	0.000	0.061	0.198	0.821	0.061	0.167	0.882
E	5	560403	2	0.106	0.000	0.046	0.259	0.928	0.061	0.213	1.141
D	2	573040	5	0.015	0.046	0.030	0.000	0.943	0.106	0.243	1.141
D	3	859561	3	0.030	0.122	0.152	0.000	0.973	0.228	0.395	1.141
D	4	1146081	2	0.015	0.046	0.076	0.000	0.988	0.274	0.471	1.141
D	5	1432601	2	0.046	0.061	0.046	0.015	1.034	0.335	0.517	1.156
D	6	1719121	1	0.091	0.030	0.030	0.076	1.125	0.365	0.547	1.232
D	7	2005642	1	0.015	0.015	0.046	0.061	1.141	0.380	0.593	1.293
D	8	2292162	1	0.000	0.015	0.061	0.000	1.141	0.395	0.654	1.293

Table 4-6 Dispersion Condition Frequency Analysis – Arthur B. Ripley Desert Woodland - Sector 101.25º – 123.75º

Dispersion Condition		$\sigma_y\sigma_z$u	Transport Time	Frequency By Time of Day (%)				Cumulative Frequency By Time of Day (%)			
Stability Class	Wind Speed (m/s)	(m^3/s)	(hours)	0-6	6-12	12-18	18-24	0-6	6-12	12-18	18-24
F	1	61984	20	0.167	0.000	0.000	0.350	0.000	0.000	0.000	0.000
F	2	123968	7	0.228	0.015	0.000	0.137	0.228	0.015	0.000	0.137
E	1	175674	20	0.015	0.015	0.000	0.015	0.228	0.015	0.000	0.137
F	3	185952	4	0.411	0.000	0.046	0.487	0.639	0.015	0.046	0.623
E	2	351348	7	0.015	0.030	0.015	0.015	0.654	0.046	0.061	0.639
D	1	475491	20	0.030	0.046	0.061	0.000	0.654	0.046	0.061	0.639
E	3	527022	4	0.076	0.015	0.046	0.046	0.730	0.061	0.106	0.684
E	4	702695	3	0.091	0.000	0.061	0.198	0.821	0.061	0.167	0.882
E	5	878369	2	0.106	0.000	0.046	0.259	0.928	0.061	0.213	1.141
D	2	950981	7	0.015	0.046	0.030	0.000	0.943	0.106	0.243	1.141
D	3	1426472	4	0.030	0.122	0.152	0.000	0.973	0.228	0.395	1.141
D	4	1901962	3	0.015	0.046	0.076	0.000	0.988	0.274	0.471	1.141
D	5	2377453	2	0.046	0.061	0.046	0.015	1.034	0.335	0.517	1.156
D	6	2852944	2	0.091	0.030	0.030	0.076	1.125	0.365	0.547	1.232
D	7	3328434	2	0.015	0.015	0.046	0.061	1.141	0.380	0.593	1.293
D	8	3803925	1	0.000	0.015	0.061	0.000	1.141	0.395	0.654	1.293

Table 4-7 VISCREEN Model Results – All Hours

Site	Background	Distance (km)	Plume Perceptibility (ΔE)			Plume Contrast (C_p)		
			VISCREEN[1]		Criteria	VISCREEN[1]		Criteria
			Theta 10	Theta 140		Theta 10	Theta 140	
Sheep Mountain Wilderness Area	Sky	59.6	0.109	0.225	2.00	0.001	-0.008[2]	0.05
	Terrain	43.0	0.615	0.061	2.00	0.005	0.001	0.05
Saddleback Butte State Park	Sky	30.6	0.638	1.133	2.00	0.003	-0.037[2]	0.05
	Terrain	26.1	4.963[3]	0.420	2.00	0.030	0.004	0.05
Antelope Valley Indian Museum State Park	Sky	24.0	0.569	0.985	2.00	0.002	-0.032[2]	0.05
	Terrain	22.8	5.645[3]	0.456	2.00	0.032	0.004	0.05
Antelope Valley California Poppy State Reserve	Sky	31.8	0.240	0.426	2.00	0.001	-0.014[2]	0.05
	Terrain	25.6	1.759	0.139	2.00	0.010	0.001	0.05
Arthur B. Ripley Desert Woodland	Sky	38.7	0.146	0.258	2.00	0.001	-0.008[2]	0.05
	Terrain	36.6	1.196	0.111	2.00	0.008	0.001	0.05

1. VISCREEN results are provided for the two VISCREEN default worst-case theta angles. The two theta angles represent the sun being in front of the observer (theta = 10 degrees) or behind the observer (theta = 140 degrees).
2. A negative C_p means the plume has a darker contrast than the background sky.
3. Exceeds screening value for plume perceptibility. Further refinement to include daylight hours only given in Table 4-8.

Table 4-8 VISCREEN Model Results – Daytime Hours (6 am – 6 pm)

Site	Background	Distance (km)	Plume Perceptibility (ΔE)			Plume Contrast (C_p)		
			VISCREEN[1]		Criteria	VISCREEN[1]		Criteria
			Theta 10	Theta 140		Theta 10	Theta 140	
Saddleback Butte State Park	Sky	30.6	0.109	0.190	2.00	0.000	-.0006[2]	0.05
	Terrain	26.1	0.915	0.072	2.00	0.005	.0001	0.05
Antelope Valley Indian Museum State Park	Sky	24.0	0.102	0.174	2.00	0.000	-0.006[2]	0.05
	Terrain	22.8	1.082	0.081	2.00	0.006	0.001	0.05

1. VISCREEN results are provided for the two VISCREEN default worst-case theta angles. The two theta angles represent the sun being in front of the observer (theta = 10 degrees) or behind the observer (theta = 140 degrees).
2. A negative C_p means the plume has a darker contrast than the background sky.

5.0 Soils and Vegetation Analysis

5.1 Regulatory Overview and Background

The PSD regulations codified at 40 Code of Federal Regulations (CFR) §52.21(o) require that an analysis of the impact to soils and vegetation of significant commercial or recreational value that would occur as a result of the project be conducted. The regulation indicates that the owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

The EPA guidance document for soils and vegetation, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA 450/2-81-078, OAQPS, Research Triangle Park, NC. December 12, 1980)* was the basis for the analysis previously submitted in the PSD application submitted in April 2009. The EPA guidance document establishes the air pollutant concentrations that are generally viewed to be protective of soils and vegetation having significant commercial or recreational value, including agricultural crops, based on a broad review of pertinent scientific literature.

During a conference call in March 2010, EPA Region 9 requested that the PHPP analysis of soils and vegetation impacts be supplemented pursuant to the following Environmental Appeals Board case: *In re: Indeck-Elwood, LLC*; PSD Appeal No. 03-04; PSD Permit No. 197035AAJ (decided September 27, 2006) ("Indeck"). The Indeck case contemplates the need for additional analysis beyond a "screening analysis" with respect to soil and vegetation for a PSD application.

Accordingly, the Indeck case was reviewed for applicability to the PHPP application. As an initial matter, key aspects of the Indeck case are not directly applicable. For example, PHPP is a clean, state-of-the-art, hybrid solar-gas-fired combined-cycle facility located within developed city limits, while the Indeck facility is a proposed large-scale coal-fired power plant located approximate to a prairie reserve of national importance. Although a more rigorous analysis is provided herein, we note that the PHPP will have substantially lower air quality impacts than would a coal-fired power plant.

The key holding of Indeck is that an agency should consider requiring more than a "screening analysis" to evaluate soil and vegetation impacts to the extent that the 1990 New Source Review (NSR) Manual would result in a different significance conclusion. In particular, the Indeck case contemplates an inventory of applicable soils and vegetation and consideration of site-specific effects where appropriate to identify potential impacts. *See*, *e.g.,* Indeck, pp. D.4-5 and D.11-12.

Following our review of Indeck, we supplemented the PHPP soils and vegetation analysis to ensure the analysis reflected the methodology in the 1990 NSR Manual (EPA, 1990). Although we believe the prior submittal achieved the standard in the 1990 NSR Manual, we are providing additional information in this submittal to better demonstrate consistency.

The guidance in the 1990 NSR Manual, Section II.C Soils and Vegetation Analysis, is brief, less than one page long. The key components of the analysis are to develop an inventory of the soils and vegetation types with commercial or recreational value found in the area, and to analyze the impacts from *regulated pollutants* that are proposed to be emitted by the facility. We believe that this requirement only applies to regulated pollutants that are to be emitted from the facility in *significant amounts*. While an example related to fluorides is provided in Section II.C, an additional example analysis provided in Section III.C of the NSR Manual clearly states "…the sensitivity of the various soils and vegetation types to each of the applicable pollutants that will be emitted by the facility *in significant amounts*." (pg D.11, emphasis added) While it may have appeared that the initial PHPP PSD application only focused on criteria pollutants and did not address the other PSD regulated pollutants (see Table A-4 in the 1990 NSR Manual), as noted on page 1-2 of this PSD application supplement, PHPP will only have significant emissions of NOx, VOC, CO, and PM/PM10/PM2.5, and hence the fact that the prior analysis only addressed modeled impacts of these pollutants is appropriate. As a clean, natural-gas fired project, PHPP will not emit any of the other regulated, non-criteria pollutants listed in Table A.4 of the NSR Manual in significant amounts.

5.2 Extent of the Analysis

The prior PSD soils and vegetation analysis conducted for the PHPP was performed for three pollutants: NOx, CO and PM10. The maximum modeled concentrations for PHPP normal operations are found in Table 6-6 of the 2009 PSD application. As shown in that table, the predicted annual NOx, as well as the 1-hour and 8-hour CO impacts did not exceed the EPA Significant Impact Level (SIL). Both the 24-hour and the annual PM10 impacts exceeded the EPA SIL. The peak PM10 impact occurred at a distance of less than 400 meters from the project boundary, in a small area on the USAF Plant 42 property in a small area northeast of the power block. Therefore, the maximum extent of the SIA for these pollutants encompasses an approximately 400 meter radius around the combined-cycle facility, although PM10 impacts only occurred in a small area near developed industrial facilities.

Because pollutant concentrations associated with Project air emissions are highest within this area, the analysis for the SIA provide conservative pollutant concentration values in regard to the regional facility impact. In addition, the SIA includes land use, terrain, soil type, and flora that is typical of the Antelope Valley in the western Mojave Desert. The SIA circle encompasses industrial land, undeveloped land, military land/airport, and commercial/light industrial properties.

In addition to analyzing impacts within the SIA, soils and vegetation types with respect to the five sensitive Class II areas identified in Section 4 (i.e., three state parks, one woodland and one wilderness area located within 50 km of the proposed Project) are discussed. The locations of these areas relative to the proposed Project are shown in the previous section in **Figure 4-1**. Due to the substantial distance beyond the SIA, pollutant impacts in these areas are significantly lower than those in the area of maximum impact within the SIA.

This supplemental soils and vegetation analysis provides additional information on the vegetation and soils inventory in the Project area and examines the potential effects of NOx, CO and PM10/PM2.5 within the Project area on these soils and vegetation types.

5.3 Vegetation Types

Some agricultural crops are grown within the vicinity of the PHPP power plant site. As noted in the AFC, these crops include primarily commercial alfalfa and onion production. Agricultural/orchard lands lie about two miles northeast and east of the power plant site (see aerial view in Figure 2-1 of the AFC, which shows evidence of crop production).

Within the defined 400 m SIA, the vegetation communities on the proposed PHPP site and immediate surrounding area can generally be classified as desert scrub, consisting primarily of perennial shrub species with an herbaceous understory of annuals that grows during the wetter and cooler spring months, as well as Joshua tree woodland.

Focused botanical surveys of the proposed project areas (power plant site and laydown area) and perimeters of buffer zones conducted in 2006 and 2008 did not reveal the presence of any federal, state, or California Native Plant Society (CNPS)-list 1 or 2 sensitive plant species. An additional survey conducted in early and late spring of 2010, limited to the power plant site, laydown area, and reclaimed water supply pipeline and buffer areas around these project components, also did not detect any such listed species. Plant species protected by the City of Palmdale's Native Desert Vegetation Ordinance were observed during these surveys. In particular, the Joshua tree (Yucca brevifolia) currently exists throughout the project site, although all of these trees on the PHPP site will be removed at the start of construction.

The closest state parks or sanctuary are located approximately 14 miles east-north-east of the proposed Project, i.e., Antelope Valley Indian Museum State Park and Saddleback Butte State Park (see Section 4). The vegetation at Saddleback Butte State Park includes spring wildflowers, creosote bushes, cholla cacti and Joshua trees at lower elevations. The Antelope Valley Indian Museum State Park has vegetation indigenous to the area. The Antelope Valley California Poppy State Reserve is on the state's most consistent poppy-bearing land. Other wildflowers growing there include owl's clover, lupine, goldfield, cream cups, coreopsis, lacy phacelia, Davy Gilia, rabbit brush, red maids, and green grasses. The Arthur B. Ripley Desert Woodland State Park protects a major stand of native Joshua trees and junipers. This park is very near the Antelope Valley California Poppy Reserve State Natural Reserve and has similar wildflowers growing there. The Sheep Mountain Wilderness has grazing land, mining activities and is used for water-related recreational use. All of these areas are quite distant to PHPP, and hence given that the PHPP emissions are very low and the maximum impacts occur in the immediate vicinity of the power plant, there would be only de minimus impacts expected to the vegetation in these parks.

No designated critical habitat areas for federally-listed species occurs within 20 miles of the power plant site. The closest Los Angeles County Significant Ecological Areas is the Little Rock Wash, which occurs about five miles to the east of PHPP power plant site.

The analysis of the air pollutants on vegetation submitted with the April 2009 PSD application was performed using the EPA 1980 screening document. There is also a screening document developed by the U.S. Department of Agriculture (USDA) entitled, *A Screening Procedure to Evaluate Air Pollution Effects in Region 1 Wilderness Areas, 1991*. The 1991 document includes plant species-specific pollutant concentration thresholds for western U.S. species, as well as other information that complements the 1980 EPA guidance. The two referenced guidance documents have been reviewed to identify the most appropriate threshold values (if available) for this region based upon the species identified that have significant commercial or recreational value.

Although the reference documents do not provide values for all of the identified species or pollutants, they do provide information about the alfalfa and onion field crops which are the primary crops in the vicinity of the project area. Based upon the information provided in Chapter 3 and Appendix B in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals*, the alfalfa were found to be rated as "sensitive" to NO_2 and the onions were found to be "resistant" to NO_2. The "sensitive" rating means that the lowest damage threshold is applied. Based upon this information, the proposed impact analysis was based upon compliance with the threshold levels for "sensitive" vegetation that are identified in Table 3.1 of *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals*. These criteria are shown for the applicable pollutants (CO and NOx) in Table 6-17 of the April 2009 PSD application.

In that table, the total modeled air concentrations for the proposed project plus ambient background concentrations are compared to the criteria to evaluate impacts. The total concentrations are well below the significance criteria for each pollutant and averaging time. Since no thresholds were exceeded, there is no potential for adverse impact on vegetation. This approach uses the most stringent level of damage threshold to assure conservative results, thus additional evaluation of impacts of air pollutants to vegetation is unnecessary.

5.4 Soils

5.4.1 Soil Types

Soils on and around the PHPP site include Adelanto coarse sandy loam, Cajon loamy sand, and Cajon loamy fine sand. Section 5.12 Soils of the PHPP AFC includes a complete list of the soil types found in Los Angeles County and the Antelope Valley Area, where the proposed project will be located.

5.4.2 Nitrogen Deposition

In addition to the ambient pollutant exposure levels (that was evaluated in the March 2009 PSD application), plants have the potential to be affected by intake of air pollutants that have deposited and subsequently accumulated in the soil. Compared to the amount of published information on the effects of atmospheric pollution on plants and animals, relatively little has been reported on their effects on soils. Often the effect on soils can be seen in plants and animals such that the impacts to soil are secondary. For instance, if contaminated soil causes vegetative damage, the result could be increased erosion, increase in solar radiation reaching the ground, higher soil temperature and moisture stress. In agricultural and populated areas, intentional human actions taken to improve soils and assist vegetation growth, such as fertilization and application of insecticides, tend to have a much more direct and profound effect on soils than airborne pollutants.

Nitrogen can be added to soil as a result of atmospheric deposition. Nitrogen deposition in soil can have beneficial effects to vegetation if they are currently lacking these elements. At levels above plant requirements, gaseous emission impacts on soils can cause acidic conditions to develop. Soil acidification and eutrophication can occur as a result of atmospheric deposition of nitrogen.

Soil Acidification

Nitrogen deposition on proximal soils is expected to occur over time as a result of PHPP operations. As noted above, nitrogen deposition acts as a plant nutrient that can benefit soils, especially soils such as sandy loam that exists in the project area. However, this soil amendment can also be detrimental where it benefits non-native plants competing with native vegetation important to herbivores like the tortoise. For PHPP, no desert tortoises were found in the vicinity of the PHPP power plant. Also, as discussed above in Section 5.3, no sensitive vegetative communities have been identified in the vicinity of PHPP that would be expected to be negatively impacted by nitrogen deposition.

Project emissions will contain nitrogen, mostly in the form of nitric oxide (NO). The NO will react in the air to form other compounds such as nitrogen dioxide (NO_2) and nitrate (NO_3) compounds. The combustion turbine generators and other combustion equipment associated with the Project have been estimated to emit up to 115 tons per year of NOx emissions, due to the combustion of natural gas and diesel fuels. Of the total NOx emissions, 35 tons of nitrogen per year would be the maximum amount of nitrogen deposited on soils situated near the Project site (assumes that all of the nitrogen emitted is deposited, rather than converted and transported out of the area, which is an extremely conservative assumption).

The AERMOD modeling that has been done for PHPP does not provide estimates of nitrogen deposition. However, in 2008, an analysis of nitrogen deposition was done for the Victorville 2 (VV2) Hybrid Power Project (AECOM, 2008) using the CALPUFF model. The CALPUFF model, which was used for the PHPP to assess potential Class I area impacts (for areas beyond 50 km), incorporates the required atmospheric chemistry and chemical transformations necessary to compute nitrogen deposition. The total modeled nitrogen deposition rates are based on the sum of wet and dry fluxes of NO_3 (as NH_4NO_3) and HNO_3 in addition to dry deposition of NO_X (assumed to be NO_2).

The CALPUFF model provides results in units of kilograms per hectare per year (kg/ha/yr). For the VV2 Project, nitrogen deposition was modeled at receptors which included the Project fence line and three nearby habitat areas of concern: riparian plant communities along the Mojave River, southwestern willow flycatcher critical habitat, and desert tortoise critical habitat (Fremont-Kramer Desert Wildlife Management Area). The maximum annual deposition rate of 0.083 kg/ha/yr was modeled to occur along the fence line to the northeast of the facility, consistent with the predominant winds which blow most frequently from the south and south-southwest. The maximum concentrations at the three habitat areas of concern were 0.033, 0.002, and 0.003 kg/ha/yr, respectively.

Another way to state these nitrogen amounts in more easily understood units, is to convert them to pounds per unit area. For example, these estimated nitrogen amount correspond to annual modeled nitrogen deposition rates for the three areas in the VV2 Project region are as follows:

- VV2 Power Plant fence line = 0.017 lbs / 10,000 ft^2
- Riparian plant communities along the Mojave River (0.8 miles to the east of the power block) = 0.007 lbs / 10,000 ft^2
- Southwestern willow flycatcher critical habitat (3.5 miles to the south-southeast of the power block) = 0.0004 lbs / 10,000 ft^2
- Desert tortoise critical habitat (4.3 miles to the north-northwest of the power block) = 0.0006 lbs / 10,000 ft^2

Similarly, the maximum of 0.017 lbs per 10,000 ft^2 estimated for the VV2 Project plant fence line is equivalent to approximately 1.2 ounces of nitrogen per acre, with smaller amounts of nitrogen expected in areas located at a distance from the Project fence line. Such nitrogen deposition rates are considered negligible as a plant growth influence. Based on these results, nitrogen deposition associated with either the VV2 Project's or the PHPP's air emissions is expected to have a negligible impact on plants growing in the vicinity. The screening document mentioned in Section 5.3 above (USDA, 1991) indicates that shrubs and herbaceous plants will have "no injury" from nitrogen deposition below 3 kg/ha/yr.

The PHPP is a hybrid solar-gas plant that is nearly identical to the VV2 Project. The predominant wind direction for PHPP is also to the northeast of the power block and there have not been any pertinent upgrades to the CALPUFF model since the analysis done in 2008. Given the similarities of the two projects, the fact that nitrogen deposition was modeled to be very low for VV2 Project, and since there are no federal habitat areas of concern near (within 20 miles) to PHPP, project-specific modeling for nitrogen deposition is not warranted.

Soil Eutrophication

Eutrophication is an increase in the concentration of chemical nutrients in an ecosystem to an extent that increases the primary productivity of the ecosystem. Atmospheric deposition of nitrogen can facilitate eutrophication of the soil and vegetation community.

A measure of the existing ambient deposition in the area was obtained from the most representative monitor (Death Valley) in the CASTNET monitoring network (EPA web site). This value is 2.2 kg/ha/yr for 2007. No screening thresholds to evaluate soil eutrophication were identified. Since the PHPP incremental annual nitrogen is expected to be very small (e.g., less than 1 percent of the ambient measured value), the effects of deposition on eutrophication is considered to be insignificant.

5.5 References for Section 5

AECOM, 2008. Exhibit C of the Victorville 2 Hybrid Power Project, Biological Assessment, Second Addendum, March.

Environmental Appeals Board case: *In re: Indeck-Elwood, LLC*; PSD Appeal No. 03-04; PSD Permit No. 197035AAJ (decided September 27, 2006).

EPA. http://www.epa.gov/castnet/.

EPA, 1990. Draft New Source Review Workshop Manual, EPA OAQPS, October.

EPA, 1980. *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* (EPA 450/2-81-078, OAQPS, Research Triangle Park, NC. December.

U.S. Department of Agriculture, 1991. *A Screening Procedure to Evaluate Air Pollution Effects in Region 1 Wilderness Areas*.

6.0 Receptor Grid Evaluation

During the March 2010 conference call, EPA questioned whether the 20 km receptor grid used in the modeling to support the PSD Application would capture the maximum modeled impacts because the grid did not include the higher terrain found at distances beyond 20 km from the project site. A review of the modeled impacts for the PSD pollutants indicated that for the 1-hour modeling periods the ancillary equipment, such as the emergency generator, controlled the modeled impacts. For those modeling periods, where the combustion turbines were the primary contributors to the modeled impacts, the location of those impacts were reviewed and found to be along the eastern fence line or within 100 meters of the fence line, indicating that the maximum impacts were downwash driven, i.e., controlled by the building cavity effects of the HRSG's, the steam generator, or the cooling tower.

For further confirmation that the modeled impacts at receptors between 20 and 50 km from the PHPP site would not have terrain-driven impacts higher than those nearby the project site caused by proximity and building cavity effects, a receptor grid was developed spanning from 20 km to 50 km from the project site in 1,000-meter intervals. The two combustion turbines were then modeled with a unit emission rate (1 gram per second [g/s]) against the existing receptor grid and the 20 to 50 km grid for comparison. The ancillary equipment (emergency engines, heat transfer fluid (HTF) heaters, auxiliary boiler, cooling towers and maintenance vehicles) were not included in this modeling due to the nature of the sources, i.e., they have short stacks, are area sources, and/or have low exit velocity. With these characteristics, their impacts do not extend more than a few hundred meters from the project fence line and would therefore have no impact at receptors 20 km or more away. The results of the modeling for the original receptor grid, the 20 to 50 km grid, and a comparison of the two are shown in **Tables 6-1**, **6-2**, and **6-3** below. As shown in **Table 6-1**, the maximum impacts from the combustion turbines within 20 km of the PHPP site range from double to fifty times higher than those at greater than 20 km depending on the period modeled. As the ancillary equipment will only contribute to the modeled impacts close to the facility, it can be concluded that the 20 km receptor grid is sufficient to capture the highest modeled concentrations.

Table 6-1 Maximum Combustion Turbine Impacts per Unit Emission Within 20 km of PHPP

Period	Modeled Concentrations ($\mu g/m^3$)			
	2002	2003	2004	Max
1-hr	12.02	12.16	11.96	12.16
3-hr	11.02	10.89	10.87	11.02
8-hr	9.62	8.83	9.23	9.62
24-hr	7.34	6.90	7.03	7.34
Annual	1.23	1.09	1.12	1.23

Table 6-2 Maximum Combustion Turbine Impacts per Unit Emission More Than 20 km of PHPP

Period	Modeled Concentrations ($\mu g/m^3$)			
	2002	2003	2004	Max
1-hr	4.06	4.89	4.46	4.89
3-hr	1.81	1.63	1.81	1.81
8-hr	0.78	0.85	0.91	0.91
24-hr	0.32	0.28	0.39	0.39
Annual	0.02	0.02	0.01	0.02

Table 6-3 Comparison of Maximum Modeled Impacts, Within 20 km vs. 20 to 50 km

Period	Maximum Modeled Unit Concentrations ($\mu g/m^3$)		
	Within 20 km	20 to 50 km	20 to 50 km impacts compared to impacts within 20 km (%)
1-hr	12.16	4.89	40.2%
3-hr	11.02	1.81	16.5%
8-hr	9.62	0.91	9.4%
24-hr	7.34	0.39	5.2%
Annual	1.23	0.02	1.4%

7.0 Growth Analysis

Similar to the other sections above, EPA indicated during the March 2010 conference call that the analysis of impacts due to project inducing growth provided in the PSD application submitted on April 1, 2009 was not sufficient. Specific guidance was not provided as to the improvements needed.

Section 5.11, Socioeconomics, of the PHPP AFC (July 2008) analyzed the potential socioeconomic impacts of the construction and operation of the PHPP. It included an evaluation of Project-related impacts on public services and infrastructure, as well as an evaluation of environmental justice. The following assessment summarizes the findings of the Socioeconomics analysis that pertain to growth inducing impacts and also provides additional information regarding the growth inducing impacts associated with the provision of electricity. As defined by the California Environmental Quality Act (CEQA) Section 15126.2(d), growth inducing impacts of a proposed project shall address the ways in which the proposed project could foster economic or population growth or the construction of additional housing, directly or indirectly. This includes projects that would remove obstacles to growth and projects that would tax existing community service facilities such that construction of new facilities would be required. The PSD requirements for analyzing growth inducing impacts is specified at 40 CFR 52.21(o) which requires simply that the owner provide an analysis of general commercial, residential, industrial and other growth associated with the source or modification.

7.1 Summary of Growth Inducing Impacts Associated with Employment

7.1.1 Construction Phase Population and Housing Impacts

The Socioeconomics analysis in the AFC concluded that nearly 350,000 construction workers are available within the combined Los Angeles, Kern, and San Bernardino county region to serve the Project, which was estimated to require 767 employees. The proposed Project would therefore draw from the construction work force in the region. It was assumed that few, if any, construction workers would permanently relocate to the nearby communities of Palmdale, Lancaster, Lake Los Angeles, Santa Clarita, etc. during the Project construction phase. This is because construction workers typically commute relatively long distances to their work sites. Should some construction workers choose to stay temporarily at a local area motel or hotel, there are at least 30 hotels in the vicinity (Palmdale and Lancaster) with rooms available to meet this demand. Should a portion of the workers relocate to the area for the duration of their construction assignments, impacts to available housing and population would be minor, as vacancy rates in Palmdale and Lancaster are both estimated at 3.7 percent. Construction impacts of the Project to population are therefore expected to be minimal, and the Project would not induce substantial population growth. Additionally, as the construction workforce is expected to either commute to the area or temporarily occupy the available supply of hotels or rentals in the area, the demand on the local housing supply is expected to be negligible. Construction of the Project would not result in a need for new housing.

7.1.2 Operation Phase Population and Housing Impacts

According to the Socioeconomics analysis in the AFC, the Project is expected to employ a total of 36 workers during operation. Some of the Project operations jobs may involve relocation to the area for workers with specialized technical or managerial skills. However, as the overall size of the workforce needed for Project operation is small, population impacts would be less than significant, especially as some of these workers would likely already be residents of the local area. Further, due to the small number of workers needed for operation of the plant and the availability of local housing, operation of the Project is expected to have an insignificant impact on housing.

7.2 Growth Inducing Impacts Associated with the Provision of Electric Power Generation

The purpose of the Project is to generate 570 MW at the PHPP through a hybrid system of natural gas-fired combined-cycle generating equipment integrated with solar thermal generating equipment. The Project will be fueled with natural gas delivered via a new natural gas pipeline. The PHPP is designed to meet the current statutory and regulatory demands for cleaner, renewable electricity in place of more traditional fossil-fuel power generation sources, such as coal.

California is actively pursuing policies to reduce GHG emissions that include adding non-GHG emitting renewable generation resources to the system mix (e.g., wind and solar). For example, Senate Bill 1078 established the California Renewables Portfolio Standard Program (RPS) program in 2002 and required 20 percent renewable energy by 2017. In 2006, Senate Bill 107 codified an accelerated new deadline into law; 20 percent by 2010. Further, in 2008, Executive Order #S-14-08 increased the goal again to 33 percent renewable energy by 2020. In addition, the Global Warming Solutions Act (Assembly Bill 32) was passed in 2006 and requires the California Air Resources Board (CARB) to develop regulations and mechanisms aimed to reduce California's greenhouse gas emissions by 25 percent by 2020.

Because renewable energy technologies are subject to intermittent operation due to variations in the weather (e.g., low wind condition or cloud cover), it is important to consider the role and necessity of also adding fossil-fuel resources such as PHPP. The roles that PHPP can fill are as follows:

1. Intermittent generation support
2. Local capacity requirements
3. Grid operations support
4. Extreme load and system emergency
5. General energy support.

The Energy Commission staff-sponsored report reasonably assumes that non-renewable power plants added to the system would almost exclusively be natural gas-fueled. Nuclear, geothermal, and biomass plants are generally base load and not dispatchable. Solid fueled projects are also generally base load, not dispatchable, and carbon sequestration technologies needed to reduce the GHG emission rates to meet the EPS are not yet developed (CEC 2009). Further, California has almost no sites available to add dispatchable hydroelectric generation.

High GHG-emitting resources, such as coal, are effectively prohibited from entering into new contracts for California electricity deliveries as a result of the Emissions Performance Standard adopted in 2007 pursuant to SB 1368. Between now and 2020, more than 18,000 GWh of energy procured by California utilities under these contracts will have to reduce GHG emissions or be replaced. This represents almost half of the energy associated with California utility contracts with coal-fired resources that will expire by 2030. If the State enacts a carbon adder or carbon tax[3], all the coal

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[3] A carbon adder or carbon tax is a specific monetary value added to the cost of a project per ton of associated carbon or carbon dioxide emissions. Because it is based on, but not limited to, actual operations and emissions

contracts may be divested at an accelerated rate as coal-fired energy becomes uncompetitive due to the carbon adder or the capital needed to capture and sequester the carbon emissions. As contracts expire, new and existing generation resources will replace the lost energy and capacity. Some will come from renewable generation; some will come from new and existing natural gas fired generation (CEC 2010). PHPP is a new plant that will support these goals.

New resources like PHPP would also be required to provide generation capacity in the likely event that facilities utilizing once-through cooling (OTC) are retired. The State Water Resources Control Board (SWRCB) and EPA have proposed significant restrictions on the operation of OTC units, which will likely require retrofit, retirement, or significant curtailment of dozens of generating units. In 2008, the OTC units collectively produced about 58,000 GWh. While those OTC facilities owned and operated by utilities and recently-built combined cycles may well install dry or wet cooling towers, it is unlikely that the aging, merchant plants will do so. Most of these units operate at low capacity factors, suggesting a limited ability to compete in the current electricity market and rely on capacity contracts, offered as these facilities are needed for reliability. Although the timing would be uncertain, new resources are expected to out-compete aging plants, displace the energy provided by OTC facilities, and facilitate, if not accelerate their retirements. Any additional costs associated with complying with the SWRCB and EPA regulation would be amortized over a limited revenue stream today and into the foreseeable future. Their energy and much of their dispatchable, load-following capability will have to be replaced. These units constitute over 15,000 MW of merchant capacity and 17,800 GWh of merchant energy (CEC 2010).

While the provision of energy supports population and housing growth, the development of power infrastructure responds to an already existing demand and projected population growth. For example, year 2000 U.S. Census Bureau results showed that the Los Angeles County population was 9,519,331 (and estimated to be 9,848,011 in 2009). The year 2000 populations of neighboring Kern and Riverside Counties were 661,649 (estimated to be 807,407 in 2009) and 1,545,374 (estimated to be 2,125,440 in 2009), respectively. In addition, the Southern California Association of Governments (SCAG) adopted the Regional Transportation Plan (2008), which showed that the population of the SCAG Region (Imperial, Los Angeles, Orange, Riverside, San Bernardino, and Ventura Counties) increased by 2 million to 18.6 million in 2007 from the previous estimate in 2000 (a 12 percent increase). More growth occurred in the SCAG region between 2000 and 2007 than did throughout the 1990's (1.9 million). The 2008 Plan also estimated that the 2035 population in the SCAG Region will be 24 million. In addition, since the 2000 U.S. Census, there was a net addition of 410,000 households to the SCAG region, which brought the regional total to approximately 5.8 million in 2007. These growth trends show that the Southern California region is expected to experience substantial population growth with or without implementation of the proposed PHPP. Rather than induce growth, the PHPP would supply energy in order to accommodate existing demand and already projected growth.

Finally, according to recent Draft Environmental Impact Reports (DEIRs) prepared by the Kern County Planning Department for the Pacific Wind Energy and PdV Wind Energy Projects, recent judicial review also supports the conclusion that additional energy supports existing demands and already projected growth. Plaintiffs in the 2007 Kerncrest Audubon Society v. Los Angeles Department of Water and Power case argued that the Environmental Impact Report (EIR) prepared for the Pine Tree Wind Development Project did not adequately address growth-inducing impacts of the Project. They

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and can be trued up at year end, it is considered a simple mechanism to assign environmental costs to a project.

argued that additional electricity generated by the Pine Tree Wind Development would result in additional growth in the Los Angeles area. The court, however, held that the additional electricity generated by the Project would meet the current forecast of growth in the Los Angeles area, and not cause growth. Therefore, it was not reasonable to require the EIR to include a detailed analysis of growth-inducing impacts. The conclusion reached in this case would apply equally to PHPP.

7.3 References for Section 7

CEC 2010. California Energy Commission Revised Staff Assessment for the El Segundo Power Redevelopment Project, CEC-700-2008-006-REV1, June 2010.

CEC 2009. Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California, CEC-700- 2009-009, MRW and Associates. May 27, 2009.

The California Energy Commission Renewables Portfolio Standards (RPS) Proceeding. http://www.energy.ca.gov/portfolio/index.html, accessed June 21, 2010.

The California Energy Commission Implementing the Renewable Energy Executive Order. http://www.energy.ca.gov/33by2020/index.html, accessed June 21, 2010.

The California Public Utilities Commission RPS Program Overview. http://www.cpuc.ca.gov/PUC/energy/Renewables/overview.htm, accessed June 21, 2010.

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Riverside County 2000. U.S. Census data http://quickfacts.census.gov/qfd/states/06/06065.html, accessed June 21, 2010.

Southern California Association of Governments 2008. Regional Transportation Plan Executive Summary http://www.scag.ca.gov/rtp2008/pdfs/finalrtp/f2008RTP_ExecSum.pdf, accessed June 21, 2010.

Southern California Association of Governments 2008 Regional Transportation Plan Chapter 2, Transportation Planning Challenges http://www.scag.ca.gov/rtp2008/pdfs/finalrtp/f2008RTP_Chapter2.pdf, accessed June 21, 2010.

County of Kern. Environmental Documents. http://www.co.kern.ca.us/planning/eirs.asp, accessed June 21, 2010.

8.0 Supplemental BACT Analysis

During the March 2010 conference call, EPA indicated that while not needed as a completeness item, additional information for the control technology evaluation would assist EPA with completing the permit in a timely manner. Therefore, as requested by EPA, the Applicant has prepared a supplemental BACT analysis for specific emission sources at the PHPP.

Specifically, EPA requested that the Applicant evaluate the following sources and control technologies:

- Electrostatic Precipitator (ESP), baghouses, and cyclones on combustion turbine generators (CTG) and heat recovery steam generators (HRSG);
- A BACT determination for CO emissions from the CTGs with and without duct burners;
- A more complete top-down BACT analysis for the auxiliary boiler and HTF heater; and
- SCR on fire-water pumps or other internal combustion engines.

8.1 Methodology

BACT is defined as the most stringent emission limitation or control technique which:

- has been achieved in practice for such category or class of source; or
- is contained in any state implementation plan (SIP) approved by the EPA for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Air Pollution Control Officer or designee that such limitation or control technique is not presently achievable; or
- is any other emission limitation or control technique, found by the Air Pollution Control Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in an Air Quality Management Plan (AQMP) or rules adopted by a local or state agency.

EPA guidance for a “top-down” BACT analysis requires reviewing the possible control options starting with the best control efficiency. In the course of the BACT analysis, one or more options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, or environmental impacts on a case-by-case (site-specific) basis. The steps required for a “top-down” BACT review are:

1. Identify available control technologies;
2. Eliminate technically infeasible options;
3. Rank remaining technologies;
4. Evaluate remaining technologies (in terms of economic, energy, and environmental impacts); and
5. Select BACT (the most efficient technology that cannot be rejected for economic, energy, or environmental impact reasons).

A device-specific and pollutant-specific BACT determination is provided in the following subsections. Each BACT determination is made through the five-step process to identify available control technologies, eliminate technically infeasible options, rank and evaluate remaining technologies, and select BACT.

8.2 Supplemental BACT for Combustion Turbines

The proposed combustion turbines will operate in combined-cycle mode. In a combined-cycle configuration, hot exhaust from the CTG is ducted through a HRSG, which is also fired, to produce steam to drive a STG. Since the combustion turbine and HRSG are coupled together in a combined-cycle configuration, and exhaust through a single stack, they are considered to be one combustion train for purposes of this evaluation of emissions control.

Because permitting activity within the past several years has resulted in lower emission standards for combined-cycle combustion turbines and a BACT analysis for the CTGs and HRSGs was prepared in the application that was submitted in April 2009, the database review focused only on determinations from April 2009 and later. The majority of determinations reviewed are based on exclusively natural gas-fired turbines. The determinations reviewed include combined-cycle turbines with a capacity greater than 100 MW. **Section 8.2.1** discusses add-on particulate controls for the CTG and HRSG system. **Section 8.2.2** evaluates CO emissions from the CTGs and HRSGs with and without duct burners.

8.2.1 Evaluation of Add-on Particulate Controls for the Combustion Turbines and HRSG

Unlike other criteria pollutants, particulate matter (PM, PM10, and PM2.5) includes a wide range of particle sizes and chemical constituents. PM consists of mostly nitrates, sulfates, ammonium, elemental carbon, and organic and inorganic compounds. PM can be emitted directly from their sources as particles, or produced as secondary particles by complex atmospheric reactions from precursor gases. SOx and NOx are currently viewed as the most significant precursors to PM; in southern California, PM contains more nitrates than in other areas of the countries (STAPPA 2006). Since PHPP has already applied BACT for NOx and SOx emissions (as well as other criteria pollutants) such that the secondary formation of PM is controlled with BACT, additional control of precursor gases will not be discussed herein.

8.2.1.1 Identification of Available Technologies

Step 1 of the five step, top-down BACT determination process is the identification of available control technologies. Particulate matter from natural gas combustion has been estimated to be less than one micron in size and has filterable and condensable fractions. In addition, AP-42 estimates the condensable fraction to be 75 percent of the total particulate emissions from natural gas combustion (EPA 2000). Note that because PM, PM10 and PM2.5 emissions generally result from impurities in the natural gas or combustion air, the controls recommended as BACT for normal operations would also represent BACT during startup and shutdown. Therefore, a separate evaluation of BACT for these transient periods was not performed.

Publicly-available information on emission control technologies was reviewed as the first step of this analysis. Databases reviewed include South Coast Air Quality Management District (SCAQMD) BACT/lowest achievable emission rate (LAER) Guidelines, EPA's Reasonably Available Control Technology/BACT/LAER Clearinghouse (RBLC), and recent or pending projects in the CEC database. Note, AVAQMD does not maintain a separate BACT database. A summary of recent RBLC evaluations is provided in **Appendix B**. Because of the limited number of applications in which add-on controls have been applied to PM2.5 emission sources, AECOM expanded its investigation to include a review of EPA guidance for particulate emissions controls, internet-based research, and general knowledge of emission control technologies based on industry experience.

EPA divides the PM2.5 control options into four different categories (STAPPA 2006):

1. Combustion of clean fuels;
2. Combustion control technologies;
3. Post-combustion control technologies; and
4. Multi-pollutant control technologies.

As PHPP has already proposed to combust pipeline-quality natural gas fuel, and to control combustion pollutants by applying BACT for NOx, SOx, CO, VOC and PM10, the cleanest selections for options 1 and 2 have already been satisfied and will not be discussed in detail. Additionally, EPA discusses the options and cost effectiveness of controlling PM2.5 with multi-pollutant control technologies rather than single-pollutant controls. The multi-pollutant controls proposed by EPA were not applied to natural gas fired equipment and, therefore, are not applicable to the CTGs and HRSGs at PHPP (STAPPA 2006).

Based on this research, the post-combustion control technologies potentially available for PM, PM10 and PM2.5 emissions from natural gas-fired equipment including CTGs and HRSGs at combined-cycle power facilities are listed below, in no particular order:

- Cyclone or multi-clone;
- Venturi (wet) scrubber;
- Electrostatic precipitator;
- Baghouse;
- Pipeline-quality natural gas fuel; and
- Good engineering (combustion and maintenance) practice.

A description of the principle of operation and general limitations for cyclones or multi-cyclones, venturi scrubbers, electrostatic precipitators and baghouses is presented below.

Cyclone

Cyclones use centrifugal and inertial forces to separate particulates from gas streams. The cyclone imparts centrifugal force on the gas stream and operates by creating a double vortex inside the cyclone body. The incoming gas is forced into circular motion down the cyclone near the inner surface of the cyclone tube, turning at the bottom of the tube, spiraling up through the center and out the top of the cyclone (EPA 2003a).

The centrifugal force of the spinning gas battles with inertial drag force of the gas traveling though the cyclone to force the particulates towards the cyclone walls. The inertial momentum of the larger particles is able to overcome the drag forces, so the particulates reach the walls and are collected at the bottom of the cyclone. Gravity also helps the larger particles reach the bottom to be collected. With smaller particulates, the centrifugal and gravitational forces are overcome by the inertial drag force and the smaller particulates are carried out of the top of the cyclone with the exiting gas (EPA 2003a).

The collection efficiently of cyclones vary with particle size and cyclone design. The collection efficiency is dependent on multiple factors such as particle size, particle density, inlet duct velocity cyclone length, dust loading, and number of gas revolutions in the cyclone. Note that the centrifugal force in, and hence efficiency of, a cyclone increases with the gas flow rate through the cyclone. Cyclones on CTGs and HRSGs are most effective at high flue gas flow rates, with collection efficiency decreasing at lower flow rates (ICAC 2010).

Cyclones are primarily used to control PM larger than 10 microns, but multiple cyclones can be used to achieve high control efficiencies for small particulates. A multiple cyclone is an array of a large number of small (several inch diameter) cyclones in parallel. Multiple cyclones have overall mass removal efficiencies of 70 to 90 percent. However, cyclone collection efficiencies fall off rapidly with particle size, so that control of fine particulate (PM2.5) is limited. While no accurate statement of collection efficiency can be made without precise details of the cyclone design and particulate properties, cyclone removal efficiencies will be 90 percent or greater for PM10, dropping to perhaps 70 percent for PM2.5, and 50 percent for one micron particles. Addition of a second multiple cyclone in series with the first will allow for increased removal efficiency.

Venturi Scrubbers

The operation of venturi (wet) scrubbers as based on the collection of particles in liquid droplets. A venturi scrubber is designed for optimal gas-liquid contact, between the waste gas and the scrubbing liquid, and optimal droplet formation. A “throat” section is built into the duct that forces the gas stream to accelerate as the duct narrows and expands. As the gas enters the venturi throat, both gas velocity and turbulence increase. Depending on the scrubber design, the scrubbing liquid is sprayed into the gas stream before the gas encounters the venture throat, or in the throat or upwards against the gas flow in the throat. The scrubbing liquid is then atomized into small droplets by the turbulence in the throat and droplet-particle interaction, which is responsible for particulate collection, is increased.

After the throat section, the mixture decelerates, and further impacts occur causing the droplets to agglomerate. Once the particles have been captured by the liquid, the wetted PM and excess liquid droplets are separated from the gas stream by an entrainment section, which usually consists of a cyclonic separator and/or mist eliminator (EPA 2003a). Typically, venturi scrubbers are applied to control emission sources with high concentrations of submicron PM. Venturi scrubbers PM collection efficiencies range from 70 percent to greater than 99 percent depending on the application and are effective in controlling both PM less than or equal to 10 microns in diameter (PM10) and PM2.5 (EPA 2003b). The control efficiency increases with increased pressure drop, which also increases operating costs.

One consideration for venturi scrubbers is that the process generates waste in the form of a slurry or wet sludge and creates the need for both wastewater treatment and solid waste disposal, which can be costly.

Electrostatic Precipitators

Electrostatic precipitators use electrical fields to remove particulate matter from CTG and HRSG flue gas. Because precipitators act only on the particulate to be removed, and only minimally hinder flue gas flow, they have very low pressure drops, and thus low energy requirements and operating costs.

In an electrostatic precipitator, an intense electric field is maintained between high-voltage discharge electrodes, typically wires or rigid frames, and grounded collecting electrodes, typically plates. A corona discharge from the discharge electrodes ionizes the gas passing through the precipitator, and gas ions subsequently ionize other particles. The electric field drives the negatively charged particles to the collecting electrodes. Periodically, the collecting electrodes are rapped mechanically to dislodge collected particulate, which falls into hoppers for removal.

While several factors determine electrostatic precipitator removal efficiency, precipitator size is of paramount importance. Size determines treatment time: the longer a particle spends in the precipitator, the greater its chance of being collected, other things being equal.

Precipitator size also is related to the specific collection area (SCA), the ratio of the surface area of the collection electrodes to the gas flow. Collection areas normally are in the range of 200 to 800 square feet per 1000 actual cubic feet per minute (ft^2/1000 acfm). In order to achieve collection efficiencies of 99.5 percent, specific collection areas of 350 to 400 ft^2/1000 acfm are typically used (ICAC 2010). Higher collection areas lead to better removal efficiencies.

Factors limiting precipitator performance are flow non-uniformity, reentrainment, and particle resistivity. More uniform flow will ensure that there are no high gas velocity, short treatment time paths through the precipitator. Attaining flow uniformity also will minimize "sneakage," or gas flows bypassing the electrical fields. Reentrainment of collected particles may occur during rapping. Proper rapper design and timing will minimize rapper reentrainment. Maintenance of appropriate hopper ash levels and of flow uniformity will minimize reentrainment of ash from the hoppers.

A key determinant of electrostatic precipitator collection efficiency is the resistivity of the particles to the flow of electric current, which affects the collection efficiency. Particles with resistivity in the range of 107 - 1010 ohm-centimeters (ohm-cm) are amenable to collection with precipitators: these particles are easy to charge, and only slowly lose their charge once deposited on a collecting electrode. Particles with low resistivity (less than 107 ohm-cm), on the other hand, lose their charge to a collecting electrode so rapidly that they tend not to adhere to the electrode, resulting in high rapping reentrainment losses. Highly carbonaceous particulate matter from natural gas combustion is an example of a low resistivity material.

Particles with high resistivity (greater than 1010 ohm-cm) can be difficult to remove with an ESP since such particles are not easily charged, and thus are not easily collected. High-resistivity particles also form particulate layers with very high voltage gradients on the collecting electrodes. Electrical breakdowns in these layers lead to injection of positively charged ions into the space between the discharge and collecting electrodes ("back corona"), thus reducing the charge on particles in this space and lowering collection efficiency.

Electrostatic precipitator overall (mass) collection efficiencies can exceed 99.9 percent, and efficiencies in excess of 99.5 percent are common. Precipitators with high overall collection efficiencies will have high collection efficiencies for particles of all sizes, so that excellent control of PM10 and PM2.5 will be achieved with well designed and operated electrostatic precipitators.

Precipitator collection efficiencies will be somewhat lower for particles with diameters near 0.3 microns. The reason for a minimum in collection efficiency for 0.3 micron particles is that both particle charge and the resistance of the gas to particle motion both increase with particle size. Near 0.3 micron, the particle charge is low enough and the resistance to particle motion is high enough that particles are collected relatively poorly. In practice, however, this effect means only that a precipitator with a 99.9 percent overall mass collection efficiency will collect over 90 percent of 0.3 micron particles, and over 97 - 98 percent of all zero to five micron particles (ICAC, 2010).

Baghouses

The Institute of Clean Air Companies describes the operation of baghouses as "conceptually simple: by passing flue gas through a tightly woven fabric, particulate in the flue gas will be collected on the fabric by sieving and other mechanisms." The dust cake which forms on the filter from the collected particulate can contribute significantly to collection efficiency.

Practical application of fabric filters requires the use of a large fabric area in order to avoid an unacceptable pressure drop across the fabric. To provide a large fabric area in a small space, the fabric is formed into cylindrical bags (hence the term baghouse). Each bag may be 20 to 30 feet long and 5 to 12 inches in diameter, and a baghouse contains multiple bags to provide sufficient fabric surface area for dust collection. For example: a 250 MW coal-fired utility boiler may have 5,000 separate bags with a total fabric area approaching 500,000 square feet (ICAC 2010).

Baghouse size for a particular unit is determined by the ratio of air flow to cloth area, typically expressed in feet per minute (cubic feet per minute of flow divided by square feet of fabric area). The selection of air-to-cloth ratio depends on the particulate loading and characteristics, and the cleaning method used. A high particulate loading will require the use of a larger baghouse in order to avoid forming too heavy a dust cake, resulting in an excessive pressure drop.

Baghouses often are capable of 99.9 percent removal efficiencies. Baghouse removal efficiency is relatively level across the particle size range, so that excellent control of PM10 and PM2.5 can be obtained.

Determinants of baghouse performance include fabric selection, the cleaning frequency and methods, and the particulate characteristics. Fabrics can be chosen which will intercept a greater fraction of particulate, and some fabrics are coated with a membrane with very fine openings for enhanced removal of submicron particulate.

Cleaning intensity and frequency are important variables in determining removal efficiency. Because the dust cake can provide a significant fraction of the fine particulate removal capability of a fabric, cleaning which is too frequent or too intense will lower the removal efficiency. On the other hand, if removal is too infrequent or too ineffective, then the baghouse pressure drop will become too high.

Baghouses are useful for collecting particles with resistivity either too low or too high for collection with electrostatic precipitators. Baghouses therefore may be good candidates for fly ash containing high unburned carbon levels, which have low resistivity, and thus are relatively difficult to collect with electrostatic precipitators" (ICAC 2010).

8.2.1.2 Technical Feasibility

Step 2 of the five step, top-down BACT determination process is the elimination of infeasible options.

From the discussion of operating methods above, it can be concluded that cyclones or multi-clones are not feasible as they are inefficient for particles less than one to three microns (EPA 1999).

As this facility will be located in the desert where water is scarce and consumption needs to be minimized, the use of any wet technology, e.g., wet or venturi scrubbers or wet electrostatic precipitators would have adverse environmental impacts to water resources. In addition, due to the impurities in the water in this desert area, a wet scrubber could have PM2.5 emissions from drift (similar to a cooling tower) that might exceed the PM2.5 emissions that it was intended to remove.

For these reasons, wet technologies are determined to be technically infeasible and have unacceptable environmental impacts, and have been eliminated from further consideration.

With dry electrostatic precipitators, there is a difficult-to-control range between 0.1 to 1.0 microns due to the size-dependent limitations of both of the contact and diffusing charging mechanisms. The precipitator is least effective for the particles in this size range. In industrial sources that generate highly carbonaceous particulate matter (e.g., natural gas combustion), the particulate resistivity can be extremely low due to the high bulk conductivity of this material at all temperatures. These resistivities can be below the levels where good performance can be obtained by flue gas conditioning. Severe rapping reentrainment problems can persist during routine operation due to the weak electrical forces bonding the dust layer to the collection plate and the ease of particle dispersion during rapping. Electrostatic precipitators are not an ideal choice for particulate matter control in these applications due to the probable emission problems (EPA 1999). Based on this information, although dry electrostatic precipitators do not appear to be an ideal choice, they cannot be considered technically infeasible and will be evaluated further.

A baghouse would not be able to capture condensable particulates, which may be as much as 75 percent of the total particulate emissions from natural gas combustion, according to EPA (EPA 2000). With the exhaust air flow being approximately 1,000,000 cubic feet per minute, the amount of filter area required could be on the order of 125,000 square feet. The pressure drop across such a large area could require a significant amount of energy to overcome. Due to the very low PM loading in the exhaust stream, the time that would be needed to establish residual dust cake on the surfaces of the fabric is a significant concern. As discussed above, it is the dust cake that is ultimately responsible for the high efficiency particulate matter removal. The particles on the fabric surface are termed the residual dust cake because they remain after normal cleaning of the bag (EPA 1999). Based on this information, although baghouses do not appear to be an ideal choice, they cannot be considered technically infeasible and will also be evaluated further.

Based on the available information, use pipeline-quality natural gas fuel and good engineering (combustion and maintenance) practice have been achieved in practice and thus cannot be eliminated from further consideration.

8.2.1.3 Rank Remaining Technologies

Step 3 of the five step, top-down BACT determination procedure is to rank the remaining technologies. Of the six potential control technologies identified for evaluation, two technologies have been eliminated from consideration as technically infeasible: cyclones and wet venturi (wet) scrubbers. Based on the qualitative information available, the remaining technologies are ranked in order of expected control effectiveness, as follows:

1. Baghouse;
2. Electrostatic precipitator;
3. Pipeline-quality natural gas fuel; and
4. Good engineering (combustion and maintenance) practice.

Note that there is limited information available on the effectiveness of either a baghouse or electrostatic precipitator for PM2.5 emissions, thus the ranking is speculative for these two technologies.

8.2.1.4 Evaluate Technologies

Step 4 of the five step, top-down BACT determination procedure is to evaluate the remaining technologies on the basis of economic, energy, and environmental impacts. For this analysis, the economic considerations are evaluated first.

State law (California Health and Safety Code [HSC] §40405) defines BACT as the lowest achievable emission rate which is the more stringent of either 1) the most stringent emission limitation contained in the SIP, or 2) the most stringent emission limitation that is "achieved in practice". There is no explicit reference to or prohibition on cost considerations.

When evaluating costs of pollution control equipment, the term “cost effectiveness” is often used. As no definition of what is considered cost-effective within the AVAQMD was found, the SCAQMD’s “cost effectiveness” definition was used in this analysis. Cost effectiveness is defined by the SCAQMD to mean:

> “Cost effectiveness is measured in terms of control costs (dollars) per air emissions reduced (tons). If the cost per ton of emissions reduced is less than the maximum required cost effectiveness, then the control method is considered to be cost effective” (SCAQMD 2000).

While the AVAQMD does not discuss cost effectiveness, guidance is available from several relevant sources, as explained below.

- SCAQMD guidelines do not allow for routine consideration of the cost of control in BACT/LAER determinations for major sources of air pollutants; however, if a proposed BACT determination results in extraordinary costs to a facility, the applicant may bring the matter to SCAQMD management for consideration.
- The SCAQMD does allow consideration cost effectiveness when BACT is established for minor sources.
- EPA guidelines state that BACT is not considered achievable if the cost of control is so great that a new source could not be built or operated with a particular control technology; however, if a facility in the same or comparable industry already uses the control technology, then such use constitutes evidence that the cost to the industry is not prohibitive.
- Several air districts in California have established guidelines for cost effectiveness in BACT determinations, as shown in **Table 8-1**.

Table 8-1 Cost Effectiveness for PM10

Agency	$/ton of Emissions Reduced
SJVAPCD	$11,400
SCAQMD[1]	$4,950
BAAQMD	$5,300

1. The SCAQMD lists the value in 2003 dollars and requires that the value be adjusted using the Marshall & Swift cost index. The cost effectiveness value shown reflects the adjustment to 2009 dollars using the adjustment factor of 1.1. (Note: The 2010 Marshall & Swift cost index is not yet available)

In the absence of specific guidance from the AVAQMD or EPA, it is assumed that EPA would take into consideration the cost of controls, if those controls were prohibitively expensive.

In absence of published cost-effectiveness values for controls on natural gas fired combustion turbines, cost estimates were compiled from a number of data sources, including the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual, published information available from equipment vendor and equipment costs recently developed for similar projects (EPA 2002), and the STAPPA/ALAPCO document *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options* (STAPPA 2006). For costing, it was assumed that each combined CTG and HRSG units would require one pollution control device; the two natural gas-fired CTGs and two HRSGs for the Project would require two PM control devices.

Capital costs include the equipment, material, labor, and all other direct costs needed to install the control technologies. Operating and Maintenance (O&M) costs were developed for each control system; only fixed operating costs were considered. Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs including the cost of consumables, including reagents (if applicable), and byproduct management were not considered for this cost analysis. Utility consumption, such as additional water and power requirement, and replacement parts were also not considered in the O&M costs. The calculated capital costs and operating costs are presented in **Table 8-2**. More detailed cost calculations are provided in **Appendix C**.

Table 8-2 Estimated Costs for PM Controls[1]

Control Device	Annualized Capital Costs ($/yr)	O&M Costs ($/yr)	Total Annualized Costs ($/yr)
Electrostatic Precipitator - 99% Control	$2,430,489	$5,728,003	$8,158,492
Baghouse - 99% Control	$1,093,720	$6,873,604	$7,967,324
1. Cost is based upon the air flow required through the control devices.			

In order to estimate cost effectiveness, the total annualized cost of the control devices were divided over 99 percent of the emissions from the CTG and HRSG units. As shown in **Table 8-2,** the lowest calculated cost effectiveness value for 99 percent control efficiency is in excess of $135,000 per ton reduced, for either technology. Since AVAQMD does not have cost effectiveness thresholds, for this analysis, the highest cost effectiveness value of $11,400 per ton from the SJVAPCD is used for comparison.

Table 8-3 Combustion Turbine Cost Effectiveness and Degree of Control

Control Device	Cost Effectiveness ($/ton PM)	SJVAPCD BACT Cost Effectiveness Threshold ($/ton PM)	Cost Effective (Yes/No?)
Electrostatic Precipitator - 99% Control	$140,750	$11,400	No
Baghouse - 99% Control	$137,450	$11,400	No

As shown in **Table 8-3**, electrostatic precipitators and baghouses exceed the SJVAPCD BACT cost effectiveness threshold and, therefore, electrostatic precipitators and baghouses are not cost effective.

8.2.1.5 BACT Determination

Based on this evaluation, cyclone or multi-clone and venturi (wet) scrubbers were determined to be technically infeasible and electrostatic precipitators and baghouses are determined to be not cost effective. A review of BACT determinations by the EPA and CARB since the original application was submitted in April indicate that no agency has required installation of add-on controls for PM10 or PM2.5.

The most specific reference to how to minimize PM10 or PM2.5 emissions from low sulfur fuel and good combustion practices was found in RBLC ID FL-0303 for the Florida Power and Light Company's West County Energy Center Unit 3. The Pollutant/Compliance Notes state:

> "The sulfur fuel specifications combined with the efficient combustion design and operation of each CTG represents BACT for PM/PM10/PM2.5 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9 (EPA, 2010)."

The lowest levels of PM10 emissions listed for similar combined-cycle turbines that use pipeline-quality natural gas and good combustion practices in the SCAQMD BACT Guidelines include Magnolia Power and Vernon City Power & Light which were discussed in the original PSD Application, which was submitted in April 2009; thus the BACT determination for PM, PM10 and PM2.5 the CTGs and HRSGs have not changed since the original application.

Based upon the results of the RBLC data search discussed previously, the use of low sulfur fuel, i.e., pipeline-quality natural gas, and good combustion practices can be considered achieved in practice. Therefore, the use of pipeline-quality natural gas and good combustion practices is determined to be BACT for the CTG and HRSGs. The applicant has proposed those technologies, low sulfur fuel and good combustion practices, for the control of PM, PM10 and PM2.5 emissions.

As the equipment and BACT determination has not changed since the application was submitted in April 2009, the proposed hourly mass emissions limits for the CTGs and HRSGs still represent BACT. The proposed hourly mass emissions limits for two turbines are 12 pounds per hour when the duct burners are off and 18 pounds per hour when the duct burners are on, with the exclusive use of pipeline-quality natural gas.

8.2.2 BACT for CO Emissions from the Combustion Turbines and HRSGs

PHPP has previously proposed to use an oxidation catalyst with good combustion practice to control CO emissions from the CTGs and HRSGs. PHPP originally proposed CO emissions limits of 2.0 ppmv dry, corrected to 15 percent O_2 over a one-hour averaging time without duct burners, and 3.0 ppmv dry (corrected to 15 percent O_2) over a one-hour averaging time when duct burners are firing through the use of an oxidation catalyst. The selection of control technology has not been disputed; however, at the request of EPA, the Applicant has reevaluated the emission limits when duct firing is utilized.

This supplemental BACT discussion focuses on the achievable CO emission limits and averaging periods for oxidation catalyst on CTGs with and without duct burners. Only emission limits below the previously proposed limits and findings after the application was submitted in April 2009 will be discussed. All systems permitted for 2 ppm CO or less employ oxidation catalyst to control CO.

Since the original application was submitted April 2009, no additional facilities were listed in the RBLC with permitted emissions limits below 2.0 ppm for CO from similar natural gas fired combined-cycle turbines. The power projects with proposed CO limits of less than 2 ppm were all permitted after April 2009 and currently are either not on-line or have not been constructed; therefore, these proposed limits have not been verified through performance testing.

A database review of the pending projects in the CEC database identified the GFW Tracy Combined Cycle Power Plant Project. The Final Staff Assessment for this project was released on October 30, 2009. This project would install two CTG and HRSG systems equipped with natural gas-fired duct burners controlled with a new higher efficiency oxidation catalyst system to limit the CO concentration to 2.0 ppmvd at 15 percent O_2 with a one-hour rolling average period (CEC 2009). Similar to the GFW Tracy Combined Cycle Power Plant Project, the to 2.0 ppmvd at 15 percent O_2 with a one-hour rolling average period should be considered as BACT for PHPP.

It is noted in the March 2009 PHPP PSD Application that the use of the Rapid Start Process (RSP) requires some modification of the CTG and HRSG to maintain the tighter seals and rapid temperature change. PHPP will also have relatively large duct burners. These differences make it more difficult to ensure that a low 2.0 ppmv emission limit can be met as there are no comparable operating power plants at which this limit is demonstrated in practice. However, based on this BACT review, the Applicant is willing to agree to a CO BACT emission limits of 2.0 ppmv dry, corrected to 15 percent O_2 over a one-hour averaging time both without duct burners and when duct burners are firing. This emission limit will be achieved with use of an oxidation catalyst.

8.3 BACT Determination for Boilers and HTF Heaters

The proposed Project will include a 110 MMBtu/hr auxiliary boiler and a 40 MMBtu/hr HTF heater. Both will be fired on pipeline-quality natural gas. The auxiliary boiler will operate a maximum of 500 hours per year, and the HTF heater will operate no more than 1,000 hours per year. The auxiliary boiler is primarily designed to shorten the duration of start-ups as part of GE's RSP technology; therefore, the boiler itself is part of the control technology designed to minimize emissions during start-up of the combustion turbines. The boiler and heater emit criteria pollutants (NOx, SOx, CO, VOC, PM10, and PM2.5) due to the combustion of natural gas.

EPA specifically requested a more complete top-down BACT analysis for the auxiliary boiler and HTF heater; this section contains BACT determinations for NOx, CO, PM/PM10/PM2.5, and VOC. PHPP is not a major source of SOx and, therefore, a SOx analysis was not conducted, although it is likely that the use of pipeline quality natural gas as fuel would also be determined to be BACT for SOx. Because the auxiliary boiler and the HTF heater are similar sources, the BACT analyses for those units are combined. A BACT analysis was provided in the original application, which was submitted in April 2009; therefore, the information review was focused only on BACT determinations from April 2009 and later.

8.3.1 NOx

NOx is formed during combustion through two primary mechanisms:

1. Thermal NOx, which is the oxidation of elemental nitrogen in combustion air; and
2. Fuel NOx, which is the oxidation of fuel-bound nitrogen.

Since natural gas is relatively free of fuel-bound nitrogen, the contribution of this second mechanism to the formation of NOx emissions in natural gas fired equipment is minimal and thermal NOx is the chief source of NOx emissions. Since fuel-bound NOx minimal from the combustion of natural gas, additional controls for fuel-bound NOx will not be discussed in this BACT analysis.

There are two basic means of controlling thermal NOx emissions from boilers: combustion controls and post-combustion controls. Combustion controls act to reduce the formation of NOx during the combustion process, while post-combustion controls remove NOx from the exhaust stream. Combustion control technologies for this type of boiler application include low-NOx burners, flue gas recirculation and staged combustion. Post-combustion controls include Selective Catalytic Reduction (SCR), non-catalytic reduction (SNCR). The technologies employed for NOx emissions control are listed below and discussed in descending order of effectiveness:

- SCR;
- SNCR;
- Ultra-low NOx burners;
- Low-NOx burners with flue gas recirculation (FGR);
- Flue gas recirculation; and
- Good combustion practice.

Selective Catalytic Reduction (SCR)

SCR was mentioned as an alternative control technology for boilers by the BAAQMD in their BACT guidance document. SCR is known to successfully control NOx to very low concentrations in large furnaces and boilers, although there is little evidence that this technology has been applied to boilers or heaters less than 50 MMBtu per hour. One key limitation relative to the technical feasibility of SCR for the proposed boiler is that the temperature of the exhaust gas (~300°F [148.89°C]) will be below the lower end of the proper temperature range for the SCR catalyst (~500°F [260°C]). The auxiliary boiler will be operated to shorten the duration of start-ups as part of GE's RSP technology and will be operated only up to 500 hours per year. The HTF heater will only be operated for 1,000 hours per year. Most of the boiler operation is expected to be at a low load, where the exhaust gas temperature will be below the minimum needed for effective SCR control. While the boiler and HTF heater will operate at full load periodically, the length of time at which the boiler and HTF heater will operate are expected to be so short that the SCR system would rarely come to full operating temperature and would rarely, if ever, achieve design control efficiency.

SCR also requires a substantial capital investment for the catalyst bed, additional power for operations (additional blower power is required to overcome the pressure drop in the catalyst bed), and the use of hazardous aqueous or anhydrous ammonia as the reducing agent. Based on the database review of boilers with similar heat rates, SCR is not used for NOx control on natural gas fired boilers in the size range of the proposed units, as evidenced by the large number of applications cited that use low NOx or ultra-low NOx burner technologies. Due to the temperature inconsistency, limited number of hours of operation, higher cost, additional energy requirements, the need to use a hazardous material (ammonia), and lack of evidence that SCR is used on boilers or heaters in the size range of the proposed units, SCR is determined to be infeasible for these devices.

Selective Non-catalytic Reduction (SNCR)

SNCR involves injection of ammonia or urea with proprietary conditions into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,200 to 2,000°F. The exhaust temperature (~300°F [148.89°C]) for the proposed auxiliary boiler and HTF heater is well below the minimum SNCR operating temperature. Therefore, SNCR is not technically feasible for this application.

Ultra-Low NOx Burners with Flue Gas Recirculation

The next most effective NOx control option is the use of ultra-low NOx burners with FGR. Ultra-low-NOx burners with FGR are commonly used on industrial-sized package boilers and heaters. These burners minimize the formation of thermal NOx, and FGR reduces the oxygen in the combustion zone to further reduce NOx formation. Ultra-low NOx burners with FGR can typically achieve NOx emission rates of nine ppm at three percent oxygen without post-combustion controls. This emission rate was recently accepted as BACT and is considered the lowest technologically feasible emission rate for this application.

PHPP will use ultra-low NOx burners with FGR and the emission limit of nine ppm as BACT for the proposed auxiliary boilers and HTF heaters. The auxiliary boiler and HTF heater will be limited to a stack NOx concentration of nine ppm at three percent oxygen with a recommended averaging period of one hour in order to comply with BACT.

The EPA, CARB, BAAQMD and SCAQMD BACT websites were researched to find actual recent BACT determinations. The most stringent requirements were those of the SCAQMD: for units with a heat input of less than 20 MMBTU/hr, the maximum allowable NOx concentration is 12 ppmv, and for units with a heat input of greater than or equal to 20 MMBTU/hr, the maximum allowable NOx concentration is 9 ppmv if a low NOx burner is utilized, and 7 ppmv if add-on controls are employed. A summary of all determinations is provided in **Appendix B**.

8.3.2 CO and VOC

CO and VOC emissions during natural gas combustion result from incomplete combustion of the gas. CO and VOC emissions are minimized by good combustion practices that promote high combustion temperatures, long residence times, and turbulent mixing of fuel and combustion air. Since these combustion practices also increase NOx emissions, the effectiveness of the NOx control system may affect the ability of the boiler and HTF heater to achieve low CO and VOC emission rates.

The technologies employed for CO and VOC emissions control in boilers and heaters are listed below in descending order of effectiveness:

- Oxidation catalyst; and
- Good combustion practice.

Oxidation Catalysts

Oxidation catalysts are known to successfully control CO and VOC to very low concentrations in large furnaces and boilers with heat rates, and little evidence that this technology has been applied to boilers or heaters of less than 50 MMBtu per hour. Oxidation catalysts are mentioned as an alternative control technology by the BAAQMD in their BACT guidance document for larger combustion sources (i.e., greater than 50 MMBtu/hour). Oxidation catalysts require a substantial capital investment for the catalyst bed, and additional power for operations (additional blower horsepower is required to overcome the pressure drop in the catalyst bed).

Based on the database review of process heaters and boilers with similar heat rates, it appears that oxidation catalysts are not used for CO and VOC control on boilers or heaters in the size range of the proposed units. Due to the limited hours of operation of the boilers and heaters, the significant number of hours of operation at low-load, substantially higher cost, additional energy requirements, and lack of evidence that oxidation catalysts are used on small boilers or heaters, oxidation catalysts are determined to be infeasible for these devices.

Good Combustion Practices

The next most effective CO and VOC control option is the use of good combustion practices. Good combustion practice is recommended as BACT for this application. Today's generation of low NOx burners seek to provide low NOx profiles through staged combustion, while simultaneously adding back oxygen to effectively burn out CO and VOC. This represents the top level of control for products of incomplete combustion from this source type.

Based on several recent BACT determinations since April 2009, 50 ppm at three percent oxygen is recommended as BACT for CO emissions. A one-hour averaging period is recommended. Both units will burn only natural gas and will achieve BACT using good combustion practices during normal operation as well as during startup and shutdown. Good combustion practice is recommended as BACT for VOC, with no specific concentration recommended for this pollutant.

The EPA, CARB, BAAQMD and SCAQMD BACT websites were researched to find actual recent BACT determinations. The most stringent control requirement for VOCs and CO was listed as flue gas recirculation, which was required primarily for NOx control. The vast majority of determinations spoke of operating in accordance with manufacturer's specification or using good combustion practices. A summary of all determinations is provided in **Appendix B**.

8.3.3 PM, PM10 and PM2.5

The technologies potentially available for PM, PM10 and PM2.5 control natural gas-fired boilers combined-cycle power facilities include the following:

1. Cyclone or multi-clone;
2. Venturi (wet) scrubber;
3. Electrostatic precipitator;
4. Baghouse;
5. Pipeline-quality natural gas fuel; and
6. Good engineering (combustion and maintenance) practice.

8.3.3.1 Technical Feasibility

Step 2 of the five step, top-down BACT determination process is the elimination of infeasible options. Technical feasibility of the above mentioned technologies as add-on controls for the PHPP boiler and HTF heater will be similar to the feasibility as add-on controls for the CTGs and HRSGs, as discussed in **Section 8.2.1**.

From the discussion of operating methods in **Section 8.2.1**, it can be concluded that cyclones or multi-clones, wet-technologies are determined to be technically infeasible, have unacceptable environmental impacts, and have been eliminated from further consideration. Only electrostatic precipitators, baghouses and of pipeline-quality natural gas fuel and good engineering (combustion and maintenance) were considered technically feasible and evaluated further.

8.3.3.2 Rank Remaining Technologies

Step 3 of the five step, top-down BACT determination procedure is to rank the remaining technologies. Of the six potential control technologies identified for evaluation, two technologies have been eliminated from consideration as technically infeasible: cyclones and wet venturi (wet) scrubbers. Based on the qualitative information available, the remaining technologies are ranked in order of expected control effectiveness, as follows:

1. Baghouse;
2. Electrostatic precipitator;
3. Pipeline-quality natural gas fuel; and
4. Good engineering (combustion and maintenance) practice.

Note that there is limited information available on the effectiveness of either a baghouse or electrostatic precipitator for PM2.5 emissions, thus the ranking is based on the expected effectiveness for PM and PM10.

8.3.3.3 Evaluate Technologies

Step 4 of the five step, top-down BACT determination procedure is to evaluate the remaining technologies on the basis of economic, energy, and environmental impacts. For this analysis, the economic considerations are evaluated first. In the absence of specific guidance from the AVAQMD or EPA, it is assumed that EPA would take into consideration the cost of controls, if those controls were prohibitively expensive. The cost for PM, PM10 and PM2.5 control is higher on a dollar per ton basis for the auxiliary boiler and HTF heater compared to the CTGs and HRSGs due to the limited number of hours of operation and lower emission rates of the heater and boiler compared to the CTG and HRSG. The highest cost effectiveness value identified from the SJVAPCD is used for comparison purposes, as AVAQMD does not publish a threshold. As shown in **Table 8-4**, add-on controls are not cost effective for either source.

Table 8-4 Boiler and Heater Cost Effectiveness and Degree of Control

Control Device	Cost Effectiveness ($/ton PM)	SJVAPCD BACT Cost Effectiveness Threshold ($/ton PM)	Cost Effective (Yes/No?)
Electrostatic Precipitator - 99% Control on Auxiliary Boiler	$1,236,674	$11,400	No
Baghouse - 99% Control on Auxiliary Boiler	$1,207,697	$11,400	No
Electrostatic Precipitator - 99% Control on HTF Heater	$461,841	$11,400	No
Baghouse - 99% Control on HTF Heater	$451,019	$11,400	No

8.3.3.4 BACT Determination for PM, PM10 and PM2.5

Based on this evaluation, cyclone or multi-clone and venturi (wet) scrubbers were determined to be technically infeasible and electrostatic precipitators and baghouses are determined to be not cost effective. Based upon the results of the RBLC data search discussed previously, the use of low sulfur fuel, i.e., pipeline quality natural gas, and good combustion practices can be considered achieved in practice. Therefore, pipeline-quality natural gas and good combustion practices is determined to be BACT for the boiler and HTF heater.

The applicant has proposed the use of these technologies: low sulfur fuel and good combustion practices for the control of PM, PM10 and PM2.5 emissions. As all PM2.5 are considered to be PM10, the BACT emissions level for PM2.5 from the auxiliary boiler and HTF heater should be the same.

8.3.4 Summary of Proposed BACT for Boiler and HTF Heater

Based on this review, the proposed BACT for the boilers is presented in **Table 8-5**.

Table 8-5 Proposed BACT for the Boiler and HTF Heater

Pollutant	Emission Limit[1]	Technology	Reference
NOx	9 ppm at three percent O_2, for units $\geq$20 MMBTU/hr heat input	Ultra-low NOx burner	SCAQMD Part D BACT for non-major polluting facilities
CO	50 ppm at three percent O_2, 1-hr average	Good combustion practice	SCAQMD Part D BACT for non-major polluting facilities
VOC	None	Good combustion practice	Various
PM, PM10, PM2.5	None	Natural gas	Various
1. The emission limits for NOx and CO would not apply during start up, shutdown or malfunction.			

8.4 Add-on NOx Controls for Emergency Diesel Generator and Fire Water Pump Engine

The PHPP will include an emergency diesel generator rated at approximately 2,000 kW and a diesel fire water pump rated at approximately 135 kW. These emergency diesel engines will each operate for a maximum of 50 hours per year for testing. Duration of emergency operation of the engines is unknown. EPA requested an evaluation of SCR on fire water pumps or other internal combustion engines. This section contains BACT determinations for NOx control on diesel-fired fire water pumps and other diesel-fired emergency engines.

The technologies employed for NOx emissions control for internal combustion engines are listed below in descending order of effectiveness:

- Selective Catalytic Reduction (SCR);
- NOx Reducing Catalyst;
- NOx Adsorber;
- Catalyzed Diesel Particulate Filter;
- Catalytic converter;
- Oxidation catalyst; and
- New Source Performance Standard (NSPS)- or Air Toxic Control Measure (ATCM)-compliant engine.

Selective Catalytic Reduction (SCR)

SCR was suggested as an alternative control technology for emergency engines by the EPA. SCR systems are being developed to control NOx emissions from stationary compression ignition engines, although there is little evidence that this technology has been applied emergency engines. SCR control systems introduce a reducing agent such as ammonia or urea into the diesel exhaust over a catalyst. The catalyst reduces the temperature needed to initiate the reaction between the reducing agent and NOx to form nitrogen and water. Both precious metal and base metal catalysts have been used in SCR systems. Base metal catalysts, typically vanadium and titanium, are used for exhaust gas temperatures between 450^{o}F and 800^{o}F. For higher temperatures (675 to 1,100^{o}F), zeolite catalysts may be used. Concerns with SCR control systems include catalyst deactivation and poisoning. Sulfur compounds in the exhaust can poison SCR catalysts and reduce the catalyst activity.

With all catalyst control systems, including SCR, oxidation, or lean-NOx catalytic controls on an IC engine, conditions exist that can reduce catalyst activity. Catalytic deactivation may result from (1) chemical poisoning, (2) masking, or (3) thermal sintering. In most cases, the reduced performance results from catalysts being masked by contaminants in the exhaust. Contaminants in diesel-fired compression ignition exhaust include oxides of sulfur and particulates. A catalyst that has been deactivated will not be as effective at reducing the target pollutants. Spent catalysts must be properly managed to prevent improper disposal. Other limitations relative to the feasibility of SCR is the substantial capital investment for the catalyst bed, additional power for operations (additional blower power is required to overcome the pressure drop in the catalyst bed), and the use of hazardous aqueous or anhydrous ammonia as the reducing agent. Based on the database review of emergency engines, SCR is not used for NOx control, as evidenced by the large number of applications cited NSPS compliant or CARB certified engines as BACT. Due to the limited number of hours of operation, higher cost, additional energy requirements, the need to use a hazardous material (ammonia), and lack of evidence that SCR is used on emergency engines, SCR is determined to be infeasible for the emergency generator and fire water pump.

Since EPA specifically requested the discussion of SCR on emergency engines, the cost effectiveness of SCR was also evaluated. EPA posted a memo from Alpha Gamma Technologies, Inc. (AGTI) on their website that evaluates the cost effectiveness for additional controls on stationary compression ignition engines (AGTI 2005). The costs effectiveness was estimated the new NSPS for stationary engines, but the cost analysis is still applicable for a BACT determination. The cost estimates are based on the annual cost for SCR of $36 per horsepower per engine, 90 percent control of the SCR, and 37 hours of operation per year. **Table 8-6** presents the costs estimates prepared by AGTI for the EPA.

As shown in **Table 8-6**, SCR on emergency diesel-fired engines is on the order of $200,000 per ton of NOx and exceeds the SJVAPCD cost effectiveness threshold of $5,700. SCR on the firewater pump and emergency generator engine is determined to be infeasible and not cost effect; therefore, SCR cannot be considered as BACT.

Table 8-6 Cost of SCR Control Per Ton of NOx Removed

Source	SCR Annual Control Costs Per Engine[1] ($/yr)	NOx Reduction per Engine[2] (g/bhp-hr)	Cost per Ton NOx Removed[2] ($/ton)
Firewater Pump (182 hp)	$6,225	0.022	$396,886
Emergency Generator (2,683 hp)	$96,588	0.312	$242,493

1. Calculated annual costs based on $36/hp
2. Numbers are presented for the applicable engine hp range. (AGTI 2005) The firewater pump is classified in the 175-300 hp range and the emergency generator is in the 1,200 to 3,000 hp range.

NOx Reducing Catalyst

A NOx reducing catalyst (NRC) system works in the same way as an SCR system, but it uses diesel fuel as a reductant instead of a urea solution. The NRC catalyst is installed in the exhaust stream much like an oxidation catalyst or diesel particulate filters and the diesel fuel reductant is injected into the exhaust ahead of the catalyst. Hydrocarbons from the injected fuel contribute to a chemical reduction reaction with the NOx in the exhaust, across the NRC catalyst. Similar to SCR, NRC will have operational limitations due to the temperature requirements of the catalyst and the limited number of hours of operation for emergency engines. Additionally, since diesel fuel is not as effective a reductant as urea, NRC systems reduce less than half as much NOx as SCR systems (STAPPA 2006). NRCs will have a high capital costs associated with the catalyst bed and there is no evidence that NRCs are used on emergency engines. NRCs are not considered as BACT for the emergency generator and fire water pump.

NOx Adsorbers and Catalyzed Diesel Particulate Filters

Unlike catalysts, which continuously convert NOx to nitrogen (N_2), the zeolite catalyst in a NOx adsorber chemically combines with NOx and stores NOx under typical lean (high oxygen content) conditions and then catalytically reduces the stored NOx under rich conditions. Since rich operation is not typical of diesel engine operation, this reduction is done by injecting fuel into the exhaust (similar to an NRC system). NOx adsorbers are typically set up as a dual bed system with a series of dampers to minimize the fuel penalty. NOx adsorber technology is expected to take a leading role in complying with the more stringent EPA Tier 4 non-road NOx standards when combined with catalyzed diesel particulate filters.

As shown in **Table 8-7**, NOx adsorbers and CDPF exceed the SJVAPCD cost effectiveness threshold of $5,700 even when combining the reductions from PM and NOx. NOx adsorbers and CDPF on the firewater pump and emergency generator engines are determined to be not cost effect; therefore, NOx adsorbers and CDPF cannot be considered as BACT for these emergency engines.

Table 8-7 Cost of NOx Adsorbers and CDPF Control for Emergency Engines

Source	Annual NOx Control Costs Per Engine[1] ($/ton NOx)	Annual PM Control Costs Per Engine[1] ($/ton PM)	Annual NOx + PM Control Costs Per Engine[1] ($/ton PM+NOx)
Firewater Pump (182 hp)	$22,049	$232,626	$20,140
Emergency Generator (2,683 hp)	$13,472	$969,121	$13,287

1. Numbers are presented from the applicable engine hp range. (AGTI 2005) The firewater pump is classified in the 175 to 300 hp range and the emergency generator is in the 1,200 to 3,000 hp range.

Catalytic Converters and Oxidation Catalysts

The next most effective NOx control option is the use of catalytic converters and oxidation catalysts. Catalytic converters and oxidation catalysts have been proposed and used on a limited number of diesel engines in California; however, neither have been used on emergency engine installations due to the high cost and limited environmental benefit (due to the low number of hours of operation). Catalytic converters and oxidation catalysts are, therefore, determined to be infeasible for this application.

NSPS- and ATCM-Compliant Engines

NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, has been adopted for non-road engines that limit emissions of NOx, VOC and CO. The specific limits vary depending upon the size, intended use, and date of manufacture of the engine. A review of the RBLC indicates that compliance with the NSPS is BACT. Compliance with the applicable NSPS is feasible and has been achieved in practice.

Title 17 Code of California Regulations (CCR) Section 93115, the California ATCM for Stationary compression ignition Engines, provides standards for new stationary emergency standby diesel-fueled engines. The California emission standards specified in Title 13 CCR Section 2423 and the PM emission limits specified in Title 17 CCR Section 93115 are at least as stringent as the requirements for a NSPS-compliant engine. Therefore, compliance with the California ATCM emission standards and limits constitutes BACT for the emergency diesel generator and fire water pump engines.

8.5 References for Section 8

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Appendix A

Electronic Archive of Modeling Files

Appendix B

Summary of BACT Evaluations

Section I: AQMD BACT Determinations
Application No.: 394164
Equipment Category - Gas Turbine

1. GENERAL INFORMATION

DATE: 1/30/2004

A. MANUFACTURER: Alstom

B. TYPE: Combined Cycle | C. MODEL: GTX100

D. STYLE: With duct burner

E. APPLICABLE AQMD RULES: 212, 218, 401, 402, 403, 407, 431.1, 475, Reg. XIII, 1401, Reg. XX, Reg. XXX, CEQA, 40CFR Part 60 subpart GG, 40CFR Part 63 NESHAPS, 40CFR Part 64, 40CFR Part 72

F. COST: $ (NA) | SOURCE OF COST DATA: Owner/Operator

G. OPERATING SCHEDULE: 24 HRS/DAY | 7 DAYS/WK | 52 WKS/YR

2. EQUIPMENT INFORMATION

APP. NO.: 394164-165

A. FUNCTION: Power Generation

B. MAXIMUM HEAT INPUT: 525 mmbtu/hr (turbine) and 73 mmbtu/hr (duct burner) | C. MAXIMUM THROUGHPUT: 43 MW gas turbine, 55 MW steam turbine

D. BURNER INFORMATION: NO.: | TYPE: Dry Low-NOx

E. PRIMARY FUEL: Natural Gas | F. OTHER FUEL:

G. OPERATING CONDITIONS: Baseload, load following

3. COMPANY INFORMATION

APP. NO.: 394164-165

A. NAME: Vernon City Light & Power | B. SIC CODE: 4911

C. ADDRESS: 2715 E 50th Street
CITY: Vernon | STATE: CA | ZIP: 90058

D. CONTACT PERSON: Mr. Carlos Fandino | E. PHONE NO.: (323) 583 - 8811x573

4. PERMIT INFORMATION

APP. NO.: 394164-165

A. AGENCY: SCAQMD | B. APPLICATION TYPE: new construction

C. AGENCY CONTACT PERSON: Chandrashekhar S. Bhatt | D. PHONE NO.: (909) 396 - 2653

E. PERMIT TO CONSTRUCT/OPERATE INFORMATION: P/C NO.: 394164 | ISSUANCE DATE: 5/27/2003
☐ CHECK IF NO P/C | P/O NO.: | ISSUANCE DATE:

F. START-UP DATE: Fall 2004 (est.)

5. EMISSION INFORMATION

APP. NO.: 394164-165

A. PERMIT

A1. PERMIT LIMIT: ppmvd @15% O_2 : NOx 2.0 (1-hr), CO 2.0 (3-hr), VOC 2.0 (1-hr), NH_3 5.0 (1-hr). PM 0.01 gr/scf and 11 lb/hr. Monthly mass limits on CO, PM10, VOC and SOx.

Section I: AQMD BACT Determinations
Application No.: 386305
Equipment Category – Gas Turbine

1. GENERAL INFORMATION				DATE: 1/30/2004
A. MANUFACTURER: General Electric				
B. TYPE: Combined Cycle		C. MODEL: PG7241FA		
D. STYLE: Includes inlet air evaporative cooling and steam injection for power augmentation				
E. APPLICABLE AQMD RULES:				
F. COST: $ (NA)	SOURCE OF COST DATA:			
G. OPERATING SCHEDULE:	24 HRS/DAY	7 DAYS/WK	52 WKS/YR	

2. EQUIPMENT INFORMATION			APP. NO.: 386305
A. FUNCTION: Power Generation			
B. MAXIMUM HEAT INPUT: 1,700 MMBtu/hr (turbine), 583 MMBtu/hr (duct burner)		C. MAXIMUM THROUGHPUT: 181 net MW (gas turbine with steam injection), 147 net MW (steam turbine)	
D. BURNER INFORMATION:	NO.:	TYPE: Dry Low-NOx	
E. PRIMARY FUEL: Natural Gas		F. OTHER FUEL:	
G. OPERATING CONDITIONS: Baseload, load following			

3. COMPANY INFORMATION			APP. NO.: 386305
A. NAME: Magnolia Power Project, SCPPA			B. SIC CODE: 4911
C. ADDRESS: 164 W. Magnolia Blvd. CITY: Burbank	STATE: CA	ZIP: 91502	
D. CONTACT PERSON: Bruce Blowey		E. PHONE NO.: 661-252-6908	

4. PERMIT INFORMATION			APP. NO.: 386305
A. AGENCY: SCAQMD		B. APPLICATION TYPE: new construction	
C. AGENCY CONTACT PERSON: John Dang		D. PHONE NO.: 909-396-2427	
E. PERMIT TO CONSTRUCT/OPERATE INFORMATION: ☐ CHECK IF NO P/C	P/C NO.: 386305 P/O NO.:	ISSUANCE DATE: 5/27/2003 ISSUANCE DATE:	
F. START-UP DATE: 5/2005 (est.)			

5. EMISSION INFORMATION	APP. NO.: 386305
A. PERMIT	
A1. PERMIT LIMIT: PPMVD@15% O2: NOx-2.0 (3-hr), CO-2.0(1-hr), VOC-2.0(1-hr), NH3-5.0(1-hr), PM: .01 gr/scf and 11 lb/hr. Monthly mass limits on CO, VOC, SOX, and PM10.	

5. EMISSION INFORMATION

APP. NO.: 386305

A2. BACT/LAER DETERMINATION: Above limits on NOx, VOC and NH3 were believed to represent prior BACT for combined cycle gas turbines. The CO limit is more stringent than prior BACT in that the concentration is lower and the averaging time is shorter.

A3. BASIS OF THE BACT/LAER DETERMINATION: Prior BACT was based on CARB's Guidance Document for Power Plant Sitings, dated September 1999 and AQMD Part D BACT. Other similar recently AQMD permitted combined cycle powerplants include LADWP Valley, LADWP Haynes, and Mountainview Power Plant. These plants were permitted with the same or similar emission concentration limits for NOx, CO, VOC, and NH3 however, they were not considered achieved in practice at the time of BACT determination. The more stringent limit on CO was proposed by the applicant.

B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: Cormetech (SCR system), Engelhard (oxidation catalyst)

B2. TYPE: SCR system and oxidation catalyst.

B3. DESCRIPTION: SCR and oxidation catalysts are integral in the HRSG. SCR catalyst nominal operating temperature is 700F; allowable operating temperature range is 450 to 850F. Aqueous ammonia (max. 19.5 wt. %) is used.

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: 386306 ISSUANCE DATE: 5/27/2003
P/O NO.: ISSUANCE DATE:

B5. WASTE AIR FLOW TO CONTROL EQUIPMENT: FLOW RATE:
ACTUAL CONTAMINANT LOADING: BLOWER HP:

B6. WARRANTY:

B7. PRIMARY POLLUTANTS: NOx, CO, VOC, PM, SOx

B8. SECONDARY POLLUTANTS: NH3

B9. SPACE REQUIREMENT: SCR Catalyst: 1,100 cu. ft; CO Catalyst: 360 cu. ft.

B10. LIMITATIONS: B11. UNUSED

B12. OPERATING HISTORY:

B13. UNUSED B14. UNUSED

C. CONTROL EQUIPMENT COSTS

C1. CAPITAL COST: ☐ CHECK IF INSTALLATION COST IS INCLUDED IN EQUIPMENT COST
EQUIPMENT: $ INSTALLATION: $ (NA) SOURCE OF COST DATA:

C2. ANNUAL OPERATING COST: $ (NA) SOURCE OF COST DATA:

D. DEMONSTRATION OF COMPLIANCE

D1. STAFF PERMFORMING FIELD EVALUATION:
ENGINEER'S NAME: INSPECTOR'S NAME: DATE:

D2. COMPLIANCE DEMONSTRATION: CEMS for NOx and CO, annual RATA, annual NH3 test, source test for SOX, VOC, and PM every three years.

D3. VARIANCE: NO. OF VARIANCES: DATES:
CAUSES:

D4. VIOLATION: NO. OF VIOLATIONS: DATES:
CAUSES:

5. EMISSION INFORMATION

APP. NO.: 386305

D5. MAINTENANCE REQUIREMENTS:

D6. UNUSED

D7. SOURCE TEST/PERFORMANCE DATA RESULTS AND ANALYSIS:

DATE OF SOURCE TEST: no later than 180 days after initial start-up

CAPTURE EFFICIENCY:

DESTRUCTION EFFICIENCY:

OVERALL EFFICIENCY:

SOURCE TEST/PERFORMANCE DATA:

OPERATING CONDITIONS:

TEST METHODS:

6. COMMENTS

APP. NO.: 386305

It should be noted that the CO emission limit has not yet been verified by performance data.

5. EMISSION INFORMATION

APP. NO.: 394164-165

A2. BACT/LAER DETERMINATION: Above limits on NOx, VOC and NH3 were believed to represent BACT for a combined cycle gas turbine. The CO limit is more stringent than prior BACT.

A3. BASIS OF THE BACT/LAER DETERMINATION: Prior BACT determination was based on CARB's Guidance Document for Power Plant Sitings, dated September 1999 and the ANP Blackstone combined-cycle power plant in Massachusetts (AQMD Public Notice 1/16/2003). The more stringent limit for CO was proposed by the applicant to reduce the offset requirements. Magnolia Power Project (A/N 386305) has similar concentration limits of NOx, CO, VOC and NH3 except for differences in averaging times (3-hr for NOx and 1-hr for VOC).

B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: Mitsubishi/Cormetec (SCR system), Emerachem (oxidation catalyst)

B2. TYPE: SCR system and oxidation catalyst

B3. DESCRIPTION: Low temperature SCR catalyst with aqueous ammonia (19% by weight)

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: 394166 ISSUANCE DATE: 5/27/2003
P/O NO.: ISSUANCE DATE:

B5. WASTE AIR FLOW TO CONTROL EQUIPMENT: FLOW RATE:
ACTUAL CONTAMINANT LOADING: BLOWER HP:

B6. WARRANTY:

B7. PRIMARY POLLUTANTS: NOx, CO, PM,VOC, SOx

B8. SECONDARY POLLUTANTS: NH3

B9. SPACE REQUIREMENT: SCR catalyst total space requirement = 1,816 cu. ft; SCR catalyst volume = 537.1 cu. ft.; CO catalyst total space requirement = 638 cu. ft; CO catalyst volume: 63 cu. ft. There are 2 such units at MGS Power Plant.

B10. LIMITATIONS:

B11. UNUSED

B12. OPERATING HISTORY:

B13. UNUSED

B14. UNUSED

C. CONTROL EQUIPMENT COSTS

C1. CAPITAL COST: ☐ CHECK IF INSTALLATION COST IS INCLUDED IN EQUIPMENT COST
EQUIPMENT: $ INSTALLATION: $ (NA) SOURCE OF COST DATA:

C2. ANNUAL OPERATING COST: $ (NA) SOURCE OF COST DATA:

D. DEMONSTRATION OF COMPLIANCE

D1. STAFF PERMFORMING FIELD EVALUATION:
ENGINEER'S NAME: INSPECTOR'S NAME: DATE:

D2. COMPLIANCE DEMONSTRATION: Source test within 180 days after startup. NOx/CO CEMS.

D3. VARIANCE: NO. OF VARIANCES: DATES:
CAUSES:

D4. VIOLATION: NO. OF VIOLATIONS: DATES:
CAUSES:

5. EMISSION INFORMATION

APP. NO.: 394164-165

D5. MAINTENANCE REQUIREMENTS:	D6. UNUSED

D7. SOURCE TEST/PERFORMANCE DATA RESULTS AND ANALYSIS:

DATE OF SOURCE TEST: CAPTURE EFFICIENCY:

DESTRUCTION EFFICIENCY: OVERALL EFFICIENCY:

SOURCE TEST/PERFORMANCE DATA:

OPERATING CONDITIONS:

TEST METHODS:

6. COMMENTS

APP. NO.: 394164-165

There is also an identical power production unit and SCR system (A/N's 394165 and 394167).

SCIENTIFIC REVIEW COMMITTEE MEETING
January 22, 2004

MEETING HIGHLIGHTS

SRC Members

Todd Wong (by phone)	Nahid Zoueshtiagh (absent)
Stan Romelczyk (by phone)	Greg Adams (represented by Seong Min)
Katy Wolf	Gary Rubenstein
Hal Taback	Karl Lany
William Dennison (absent)	Steve Simons (represented by Noel Muyco)
Martin Ledwitz	Ted Guth
Anoosheh Mostafaei (absent)	Russell Greenhouse (absent)
Phillip Hodgetts	Ronald Wilkness
Ron Joseph (absent)	

Attendees

Duc Tran (by phone)	Millie Yamada
Gabe Trinidad	Steve Hurlock
John Billheimer	Dale Botts
Viji Sadasivan	Ken Hudson
Jerry Kraim	

AQMD Staff

Marty Kay	Alfonso Baez
Howard Lange	John Yee

The handouts and audiotapes can be obtained through the Public Records Section of the Chief Prosecutor's Office. There may be a fee for this service.

Marty Kay welcomed the SRC members and the audience to the meeting. The topics listed below were discussed during the meeting.

- Minutes of November 20th Meeting
- Responses to Comments from November 20th Meeting
- New and Updated BACT - Part B Listings
- Proposed Updates of BACT - Part D (MSBACT) guidelines
- Other Business

Minutes of the November 20th Meeting

A committee member requested the following clarification: on page 3 of the minutes, in the phrase "…with the Rule 1171 limits on the VOC content of blanket and roller washes dropping from 600 to 800 g/l to 100 g/l in July 2005…", the words "600 to 800" should more appropriately be "600 and 800". AQMD staff agreed to make the change. *(Katy Wolf, IRTA; Marty Kay, AQMD)*

Responses to Comments from the November 20th Meeting

AQMD staff stated that changes in the listings presented at the November 20th meeting that had been agreed upon at the meeting, as well as any agreed-upon changes in the minutes from the prior meeting, had been made. Committee and audience members could check the final listings and minutes as posted on AQMD's web site.

At the November 20th meeting, AQMD staff had agreed to investigate and report back to the committee on the following two items:

1. Regarding the new Part B LAER/BACT listing for publication rotogravure printing (Quad Graphics in West Virginia), a committee member had requested that AQMD staff attempt to obtain information on the VOC loading of the air entering the VOC removal system. AQMD staff reported that the information had been obtained and added to the listing. *(Howard Lange, AQMD)*
2. Regarding the proposed update of the Part D guideline for lithographic printing, a committee member had suggested that the vapor pressure limit on blanket and roller washes be deleted as of July 2005, when the washes must comply with a 100 g/l VOC limit (Rule 1171). AQMD staff had discussed this with the permitting team that handles lithographic printing, and the team had agreed to modify the BACT guideline to allow the 100 g/l rule requirement to be met in lieu of the vapor pressure limit. *(Howard Lange, AQMD)*

New BACT Part B, Section I Listings

Fiberglass Impregnation System, Nelco Products (A/N 394320)

In this facility, Nelco Products manufactures resin-impregnated fiberglass cloth, commonly known as “pre-preg”. Pre-preg is an intermediate product that is used in manufacture of printed circuit boards, golf clubs, fishing poles, etc. Fiberglass cloth is drawn through a dip tank containing a resin-solvent mixture and then through an oven for driving off the solvent and partially curing the resin. AQMD staff noted that this equipment is subject to Rule 1128 and suggested that the term “fiberglass impregnation system” should perhaps be changed to “fiber coating system” to be consistent with the rule.

In that Nelco Products had claimed confidentiality in its application for this equipment, only limited information regarding equipment dimensions and process rate was included in the listing. The air flow rate through the oven in part 2 of the listing (4900 cfm) was incorrect and was to be changed. In addition to compliance with Rules 1128 and 1171, the facility meets a permit condition requiring 98% overall control of VOC. Compliance with Rule 1171 is by use of acetone for cleanup. Since the facility uses a resin-solvent mixture with 375 g/l VOC content, which exceeds the 265 g/l maximum in Rule 1128, compliance with Rule 1128 is by the 98% overall VOC control. However, the 98% substantially exceeds the 85.5% required by the rule. The 98% control is achieved by permanent total enclosure of the dip tank and oven and venting to a thermal oxidizer. A source test certified the permanent total enclosure and showed the thermal oxidizer to achieve 99.4% destruction efficiency. *(Marty Kay, AQMD; Howard Lange, AQMD)*

Discussion: A committee member expressed concern with the widespread use of acetone as a cleanup solvent in various plastic-based industries and asked whether there have been any acetone explosions reported. Another committee member responded that fire departments limit the amounts that can be stored and that, to her knowledge, no explosions have occurred. An audience member asked about a statement in part 6 of the listing (Comments) that the oxidizer had failed to meet the 98% destruction efficiency. AQMD staff explained that the statement referred to a previous source test and that the problem had been fixed and the unit retested. AQMD staff agreed to clarify the statement. Another audience member noted that the oxidizer was required to have a minimum temperature of 1400F and asked where that temperature is measured. AQMD staff responded that the temperature is measured at the outlet end of the oxidizer chamber. *(Hal Taback, HTC; Katy Wolf, IRTA; ; Howard Lange, AQMD; Marty Kay, AQMD)*

Gas Turbine, Combined Cycle – Magnolia Power (A/N 386305)

This is a combined cycle power plant consisting of a 181 MW gas turbine with a separately fired heat recovery steam generator and a 147 MW steam turbine. Permit limits are as follows (ppmvd@15%O2): NOx-2.0 (3-hr avg.), CO-2.0 (1-hr avg.), VOC-2.0 (1-hr avg.), NH3-5.0 (1-hr avg.). These limits were considered BACT at the time the Permit to Construct was drafted. The limits were based on 1999 CARB guidance for power plants and AQMD Part D BACT. The CO limit is, however, more stringent than either of those guidelines and was offered by the applicant. To achieve these emission limits, the gas turbine is equipped with a dry low-NOx burner and the plant includes an SCR and oxidation catalyst. The plant is still under construction. *(Howard Lange, AQMD)*

Discussion: A committee member noted that the Permit to Construct issue dates of this plant and the Vernon plant, to be discussed next, were the same and yet the NOx averaging times were different—3-hr in this case (Magnolia) and 1-hr in the other case (Vernon). AQMD staff explained that the Magnolia permitting process had begun earlier than the Vernon permitting process, and the Vernon permit conditions therefore reflected more recent, and more stringent, BACT. An audience member asked whether BACT for NOx for gas turbines of this type is now 2.0 ppm with a one-hour averaging time. AQMD staff responded that it is. A committee member clarified that this BACT applies to large combined cycle gas turbines and not necessarily to smaller, simple cycle gas turbines. *(Gary Rubenstein, Sierra Research; John Yee, AQMD; Marty Kay, AQMD; Howard Lange, AQMD)*

Gas Turbine, Combined Cycle – Vernon City (A/N 394164)

This power plant consists of two identical combined cycle power trains. Each power train includes a 43 MW gas turbine, separately fired heat recovery steam generator and 55 MW steam turbine. Each gas turbine has a dry low-NOx burner, and each power train includes SCR and oxidation catalyst for additional emission control. Permit limits are as follows (ppmvd@15%O2): NOx-2.0 (1-hr avg.), CO-2.0 (3-hr avg.), VOC-2.0 (1-hr avg.), NH3-5.0 (1-hr avg.). These limits were considered BACT at the time the Permit to Construct was drafted. The limits were based on 1999 CARB guidance for power plants and AQMD Part D BACT. The permit conditions also include a monthly mass limit on VOC that is equivalent to 1.2 ppmvd@15%O2, which was requested by the applicant. *(Howard Lange, AQMD)*

Discussion: Several committee members noted that the 5 ppm ammonia limits on both combined cycle plants has not been achieved in practice and may be difficult to achieve. One committee member asked whether the 5 ppm limit is now BACT for NH3 for this equipment category and whether AQMD may potentially relax this BACT guideline if it proves to be too difficult to meet. AQMD staff responded that the 5 ppm limit is now considered to be BACT but it can be relaxed if necessary. AQMD staff noted that for low-NOx turbines such as the GE 7FA used in the Magnolia case (6-9 ppm NOx), meeting a 5 ppm NH3 limit should not be difficult. Committee members responded that meeting the limit may still be difficult because of imperfect mixing and gas sneakage through inadequately sealed spaces between catalyst blocks. A committee member pointed out that large combined cycle plants now frequently have low utilization, and evaluation of achieved-in-practice should consider actual operation time.

A committee member noted that the SCR and oxidation catalyst volumes specified in the two listings, on a comparative basis, seemed inconsistent with the plant sizes. AQMD staff agreed to investigate and correct any erroneous data.

A committee member asked how the monthly mass limit on VOC is enforced. AQMD staff responded that enforcement of that limit will be based on the results of an annual source test and noted that if the 1.2 ppm limit was not met, the plant would simply have to purchase additional offsets. Committee members suggested that since the 1.2 ppm limit is essentially a "soft" limit, it should not be included as BACT. AQMD staff agreed to clarify this in the listing. *(Hal Taback, HTC; Gary Rubenstein, Sierra Research; Ted Guth, Consultant; Karl Lany, SCEC; Marty Kay, AQMD; John Yee, AQMD; Howard Lange, AQMD)*

Gas Turbine, Simple Cycle – EI Colton (A/N 406065)

This is a simple cycle gas turbine power plant rated at 48.7 MW. The turbine is equipped with water injection for NOx control and also with SCR and oxidation catalyst. Permit limits are as follows (ppmvd@15%O2): NOx-3.5 (3-hr avg.), CO-6.0 (3-hr avg.), VOC-2.0 (3-hr avg.), NH3-5.0 (3-hr avg.). These limits were considered BACT at the time the Permit to Construct was drafted. The BACT determination was based on CARB's guidance for power plants. The 3.5 ppm NOx limit, however, is lower than the 5 ppm suggested in the CARB guidance, and was offered by the applicant. The unit was source tested and met all permit limits. *(Howard Lange, AQMD)*

Discussion: A committee member suggested that the SCR catalyst design temperature be noted in LAER/BACT listings for simple cycle gas turbines because it is a key parameter affecting what NOx and NH3 limits can be met. This committee member noted also that two or three similar (GE LM6000) projects in AQMD jurisdiction with similar limits are not meeting their limits and are under variance. AQMD staff agreed to investigate this and add appropriate information to the listing. Another committee member suggested that AQMD staff also look at the CEMS data and Rule 218 (c) CO data., and AQMD staff agreed to check this information if available. *(Gary Rubenstein, Sierra Research; Karl Lany, SCEC; Marty Kay, AQMD)*

New BACT Part B, Section II Listing

Gas Turbine, Simple Cycle – Lambie Energy Center (BAAQMD A/N 6510)

This 49.9 MW simple cycle power plant was cited in CARB's report to the legislature on NOx controls for power plants. The turbine is equipped with SCR and oxidation catalyst. Permit limits are as follows (ppmvd@15%O2): NOx-2.5 (3-hr avg.), CO-6.0 (3-hr avg.), VOC-2.0, NH3-10. These limits were based on CARB guidance for power plants, however, the 2.5 ppm limit on NOx is more stringent than the 5 ppm limit suggested by the CARB guidance, and was offered by the applicant. The unit has been source tested and met all permit limits. *(Howard Lange, AQMD)*

Discussion: A committee member noted that the mass limit on PM10 emissions in this permit is 3 lb/hr whereas the corresponding limit in the EI Colton permit (above) is 11 lb/hr. Another committee member explained that the 3 lb/hr limit is probably based on the guarantee normally offered with this size turbine, which is based, in turn, on the resolution capability of the test method. Another committee member pointed out that the 11 lb/hr limit is probably based on an old AQMD prohibitory rule.

A committee member requested that AQMD staff add information on catalyst manufacturers, catalyst volumes, guarantees provided by the catalyst system vendor and catalyst design temperatures. AQMD staff agreed to attempt to obtain this information.

A committee member noted that the plant has not accumulated sufficient operation for the concentrations limits to be deemed achieved in practice. AQMD staff agreed that there apparently has not been enough operation but noted that BAAQMD changed their BACT guideline to these limits in July 2003. AQMD staff agreed, however, to hold back the listing until sufficient operating days have been accumulated or a permit is issued with a BACT determination requiring the same limits. Two other committee members noted that the Modesto Electric Generating System (MEGS) project in the San Joaquin valley air district is probably going to have similar limits, but were not sure whether it was a BACT determination or offered by the applicant. The same committee member requested that AQMD staff add information regarding NOx exceedances mentioned in part 5D2 of the listing—specifically, what were the design errors causing these exceedances. AQMD staff agreed to attempt to obtain this information. *(Ted Guth, Consultant; Gary Rubenstein, Sierra Research; Noel Muyco, Southern California Gas Co.; Karl Lany, SCEC; Howard Lange, AQMD)*

Proposed Updates of Part D (MSBACT) Guidelines

Update of MSBACT for Stationary (Non-Emergency) I.C. Engines Rated at or above 2064 BHP

Current MSBACT guidelines for stationary I.C. engines rated at or above 2064 bhp for NOx and CO are 21 ppmvd@15%O2 multiplied by engine efficiency (HHV) divided by 33 and 33 ppmvd@15%O2, respectively. There is no MSBACT for VOC or NH3. The new Part B listing of NEO California Power's large stationary engines presented at the September 2003 SRC meeting (16 engines rated at 3870 bhp and approximately 39% efficiency [HHV], started up in 2001) documented permit conditions of 9 ppmvd@15%O2 NOx, 56 ppmvd@15%O2 CO, 25 ppmvd@15%O2 VOC and 10 ppmvd@15%O2 NH3, all of which had been demonstrated in a source test. Based on that case, AQMD proposed to lower the NOx MSBACT guideline for this equipment category to 9 ppmvd@15%O2 and add MSBACT for VOC and NH3 of 25 and 10 ppmvd@15%O2, respectively. AQMD proposed to leave the MSBACT guideline for CO unchanged since the CO limit in the NEO California Power permit is less stringent than the existing MSBACT guideline. Handouts showing the proposed changes and cost effectiveness calculations were available to all attendees. *(Marty Kay, AQMD)*

Discussion: A committee member suggested that it would be simpler to adjust the guidelines for NOx, VOC and CO to 0.15, 0.15, 0.6 g/bhp-hr, respectively, to be consistent with the guideline for smaller stationary I.C. engines. AQMD staff responded that concentration limits are preferable because uncertainty in determining the power level at which an engine is operating makes g/hp-hr limits difficult to enforce. AQMD staff added that applying an efficiency ratio to the ppm guideline is also undesirable because of uncertainty in determining the engine's efficiency (e.g., even the specified full-load efficiency is frequently uncertain because the information available with the engine frequently does not specify LHV or HHV basis). The same committee member expressed concern that a fixed ppm limit based on the NEO engines may be difficult for other engines that are more efficient. AQMD staff responded that the NEO engines have rated efficiency of about 39% (HHV), which is quite high for this type of engine. Another committee member suggested that applying an efficiency ratio would allow a higher ppm limit for more efficient engines. AQMD staff responded that that approach would also make it more difficult for less efficient engines.

A committee member pointed out that the NEO engines do not have CEMS whereas similar engines in the South Coast would be required to have CEMS and it would be more difficult to comply with the emission limits with CEMS monitoring as opposed to annual source testing. AQMD staff responded that two NEO engines, selected by the APCD, had been tested a year after the initial source test and were found to be still in compliance, although the NOx and CO levels had increased. Another committee member noted that the NEO limits may not be suitable for all similar engines because I.C. engines operate in a wide range of duty cycles.

A committee member asked what was the averaging time associated with the NEO limits. AQMD staff responded that there were no apparent averaging times in the permits, but AQMD would lean toward a 1-hr average. Another committee member expressed concern regarding keeping the MSBACT guideline for CO the same while lowering the NOx guideline. AQMD staff noted that the CO levels measured in the source test were less than 33 ppmvd@15%O2 for all engines and pointed out that there should not be a NOx-CO tradeoff in this case because the emission control technology (SCR and oxidation catalyst) affords independent control of NOx and CO.

It was agreed that since AQMD did not plan to bring this matter before its Board until June 2004, it could be discussed again at the next meeting. *(Karl Lany, SCEC; Gary Rubenstein, Sierra Research;Marty Kay, AQMD; Howard Lange, AQMD)*

Update of MSBACT for Dry Cleaning; Incinerator—Non-Infectious, Non-Hazardous Waste; Pharmaceutical Manufacturing; Polystyrene Manufacturing

Staff stated that AQMD also planned to update MSBACT guidelines for several other equipment categories including Dry Cleaning, Incinerator—Non-Infectious, Non-Hazardous Waste, Pharmaceutical Manufacturing and Polystyrene Manufacturing. A handout was available to all attendees showing the proposed changes. The proposed changes to the Dry Cleaning and Pharmaceutical Manufacturing guidelines consisted of adding "compliance with Rule 1102" and "compliance with Rule 1103", respectively. The proposed change in the guideline for Incinerator—Non-Infectious, Non-Hazardous Waste was to delete the words "upon final promulgation of the regulation" from a footnote that refers to 40 CFR 60, Subpart CCCC since that regulation has now been promulgated. Polystyrene Manufacturing was to be deleted as a separate equipment category and become a subcategory under Resin Manufacturing. *(Marty Kay, AQMD)*

Discussion: Regarding the MSBACT guidelines for Dry Cleaning, a committee member suggested that: (1) the requirement of a refrigerated condenser be deleted from the guideline for petroleum solvent dry cleaning in that AQMD has permitted numerous petroleum solvent dry cleaning systems without refrigerated condensers and (2) the subcategory "Valclene" be deleted in that Valclene is no longer used for dry cleaning. A second committee member agreed that Valclene is probably no longer used for dry cleaning. The first committee member also noted that Valclene is chemically equivalent to "CFC-113" and was banned from production in 1996. AQMD staff agreed to investigate and consider these suggestions. *(Katy Wolf, IRTA; Todd Wong, CARB; Marty Kay, AQMD)*

Other Business

Marty Kay announced that the date of the next meeting would be March 25 and thanked all attendees for their participation.

There was no further discussion, and the meeting was closed.

Attachments

RBLCID	FACILITY NAME	PROCESS NAME	THROUGHPUT	UNIT	NOX CONTROL METHOD DESCRIPTION	EMISSION LIMIT	UNIT	AVERAGING TIME
AR-0090	NUCOR STEEL, ARKANSAS	PICKLE LINE BOILERS	12.6	MMBTU/H	LOW NOX BURNERS	2.9	LB/H	
LA-0192	CRESCENT CITY POWER	FUEL GAS HEATERS (3)	19	MMBTU/H	LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	1.81	LB/H	
NV-0046	GOODSPRINGS COMPRESSOR STATION	COMMERCAIL/INSTITUTION BOILER	3.85	MMBTU/H	GOOD COMBUSTION PRACTICE	0.1010	LB/MMBTU	
NV-0047	NELLIS AFB	BOILERS/HEATERS	6.5	MMBTU/H	LOW NOX BURNER AND FLUE GAS RECIRCULATION	0.0300	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT HA08	8.37	MMBTU/H	LOW NOX BURNER	0.0146	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT FL01	14.34	MMBTU/H	LOW NOX BURNER AND FLUE GAS RECIRCULATION	0.0353	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT BA01	16.8	MMBTU/H	LOW NOX BURNER AND FLUE GAS RECIRCULATION	0.0300	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT BA03	31.38	MMBTU/H	LOW NOX BURNER	0.0306	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT CP01	35.4	MMBTU/H	LOW NOX BURNER	0.0350	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT CP03	33.48	MMBTU/H	LOW NOX BURNER	0.0367	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT CP26	24	MMBTU/H	LOW NOX BURNER	0.0108	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT PA15	21	MMBTU/H	LOW NOX BURNER	0.0366	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT IP04	16.7	MMBTU/H	LOW NOX BURNER	0.0490	LB/MMBTU	
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	AUXILIARY BOILER	150	MMBTU/H		21	LB/H	
OR-0046	TURNER ENERGY CENTER, LLC	ELECTRICAL POWER GENERATION	34507448	MMBTU/YR	SELECTIVE CATALYTIC REDUCTION	2	PPMVD	1-H BLOCK
OR-0046	TURNER ENERGY CENTER, LLC	AUXILIARY BOILER	417904	MMBTU/YR	SELECTIVE CATALYTIC REDUCTION	0.011	LB/MMBTU	3-H BLOCK
WA-0301	BP CHERRY POINT REFINERY	PROCESS HEATER, IIHT	13	MMBTU/H	ULTRA LOW NOX BURNERS	0.1000	LB/MMBTU	24 HR AVE, 7% O2
WV-0023	MAIDSVILLE	AUXILIARY BOILER	225	MMBTU/H	LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.098	LB/MMBTU	3 HOUR ROLLING AVERAGE
AR-0090	NUCOR STEEL, ARKANSAS	PICKLE LINE BOILERS	12.6	MMBTU/H	GOOD COMBUSTION PRACTICE	0.2	LB/H	
LA-0192	CRESCENT CITY POWER	FUEL GAS HEATERS (3)	19	MMBTU/H	GOOD COMBUSTION PRACTICES	0.1000	LB/H	
NV-0046	GOODSPRINGS COMPRESSOR STATION	COMMERCAIL/INSTITUTION BOILER	3.85	MMBTU/H	GOOD COMBUSTION PRACTICE	0.0052	LB/MMBTU	
NV-0047	NELLIS AFB	BOILERS/HEATERS	6.5	MMBTU/H	FLUE GAS RECIRCULATION	0.0062	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT HA08	8.37	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0054	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT FL01	14.34	MMBTU/H	FLUE GAS RECIRCULATION	0.0054	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT BA01	16.8	MMBTU/H	FLUE GAS RECIRCULATION	0.0054	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT BA03	31.38	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0054	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT CP01	35.4	MMBTU/H	FLUE GAS RECIRULATION AND OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0054	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT CP03	33.48	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0054	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT CP26	24	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0054	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT PA15	21	MMBTU/H	N/A	N/A	LB/MMBTU	
NV-0049	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT IP04	16.7	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0053	LB/MMBTU	
WA-0301	BP CHERRY POINT REFINERY	PROCESS HEATER, IIHT	13	MMBTU/H	N/A	N/A		

Appendix C

Preliminary Cost Effectiveness Calculation

	CTGs and HRSG			Auxiliary Boiler			HTF Heater		
Direct costs	**Electrostatic precipitator**	**Venturi scrubber**	**Fabric filter**	**Electrostatic precipitator**	**Venturi scrubber**	**Fabric filter**	**Electrostatic precipitator**	**Venturi scrubber**	**Fabric filter**
Purchased equipment									
Exhaust Flow Rate (Ft3/min)	946,777	946,777	946,777	28,416	28,416	28,416	10,612	10,612	10,612
Capital costs	**$18,935,547.60**	**$2,366,943.45**	**$8,520,996.42**	**$568,314.11**	**$71,039.26**	**$255,741.35**	**$212,239.30**	**$26,529.91**	**$95,507.68**
Adjustment factor	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Annualized Capital Costs	**$2,430,489.07**	**$303,811.13**	**$1,093,720.08**	**$72,946.46**	**$9,118.31**	**$32,825.91**	**$27,242.16**	**$3,405.27**	**$12,258.97**
Operating & maintenance costs	**$4,733,886.90**	**$4,165,820.47**	**$5,680,664.28**	**$142,078.53**	**$125,029.10**	**$170,494.23**	**$53,059.82**	**$46,692.65**	**$63,671.79**
Annualized capital costs + operating costs x CPI 2002 - 2010 (21%)	**$8,158,492.22**	**$5,344,453.90**	**$7,967,323.86**	**$244,861.48**	**$160,403.52**	**$239,123.93**	**$91,444.55**	**$59,903.37**	**$89,301.84**
Emissions from 99% Removal	57.96		57.96	0.20		0.20	0.20		0.20
Cost effectiveness for 99% removal ($/ton PM)	$140,749.81		$137,451.78	$1,236,674.15		$1,207,696.62	$461,841.17		$451,019.39

References

STAPPA/ALAPCO. Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options, Chapter 5, Boiler Technologies, March 2006 - low end of cost range is used throughout this

Equipment type	Capaital cost , $/scfm	O&M cost, $/scfm
Reverse-air cleaned filter	9 - 85	6 - 27
Wet wire-plate ESP	20 - 40	5-40
Venturi scrubber	2.5 - 21	4.4 - 120

STATE OF CALIFORNIA
ENERGY RESOURCES
CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of:	)	Docket No. 08-AFC-9
	)	
Application for Certification, for the CITY OF PALMDALE HYBRID POWER PLANT PROJECT	)	**PROOF OF SERVICE**
	)	(Revised January 14, 2011)

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PALMDALE HYBRID POWER PROJECT
CEC Docket No. 08-AFC-09

DECLARATION OF SERVICE

I, Paul Kihm, declare that on January 25, 2011, I served and filed copies of the attached document to all parties identified on the Proof of Service List above in the following manner:

APPLICANT'S LETTER TO U.S. EPA REGARDING SUPPLEMENTAL INFORMATION FOR THE APPLICATION FOR PSD PERMIT, DATED JULY 21, 2010 (WITH ENCLOSURE)

California Energy Commission

☒ Transmission via electronic mail and by depositing a copy with FedEx overnight mail delivery service at Costa Mesa, California, with delivery fees thereon fully prepaid and addressed to the following:

CALIFORNIA ENERGY COMMISSION
Attn: DOCKET NO. 08-AFC-09
1516 Ninth Street, MS-4
Sacramento, California 95814-5512
docket@energy.state.ca.us

For Service to All Other Parties

☒ Transmission via electronic mail to all email addresses on the Proof of Service list; and

☒ by depositing one paper copy with the United States Postal Service via first-class mail at Costa Mesa, California, with postage fees thereon fully prepaid and addressed as provided on the Proof of Service list to those addresses **NOT** marked "email preferred."

I further declare that transmission via electronic mail and U.S. Mail was consistent with the requirements of California Code of Regulations, title 20, sections 1209, 1209.5, and 1210.

I declare under penalty of perjury that the foregoing is true and correct. Executed on January 25, 2011, at Costa Mesa, California.

Paul Kihm

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